Norwegian University
of Life Sciences

Master's Thesis 2016 30 ECTS
Faculty of Social Sciences
School of Economics and Business

Energy from Iceland:

The Feasibility of Exporting Electricity from Iceland to the United Kingdom

Ingvar Freyr Ingvarsson
Master of Science in Economics

Acknowledgments

I would like to thank my supervisors, Knut Einar Rosendahl and Olvar Bergland, for their many valuable comments on previous drafts of this thesis. Their unending support has contributed immensely to every aspect of this study.

I would also like to thank all the individuals and companies who have provided me with essential data and other information - this journey would not have been possible without their support: Svandís Hlín Karlsdóttir (Landsnet), Björgvin Skúli Sigurðsson, Úlfar Linnet and Magnús Sigurðsson (Landsvirkjun), Jónas Hlynur Hallgrímsson (EFLA), Helgi Tómasson and Þórólfur Matthíason (University of Iceland), Daníel Svavarsson (Landsbankinn).

Finally, I am very grateful to Finn Roar Aune (Statistics Norway) for running the simulation used in the first part of this thesis.

I take full responsibility for any mistakes and omissions present within this thesis.

Ingvar Freyr Ingvarsson

Kópavogur, Iceland, August 2016

Abstract

This study examines the impact of building a subsea power cable between Iceland and the UK. It aims to provide a better understanding of the cost and benefits associated with the international liberalisation of Iceland's electricity market. The first part of the thesis explores the simulation results of a large-scale simulation model for the European energy market (LIBEMOD), where a cable has been implemented. The model accounts for total energy produced, as well as total energy consumed, in each of the model countries, including the 27 countries of the European Union, Iceland, Norway and Switzerland.

The second part of the thesis mainly focuses on the decision for buying and selling electricity through a subsea power cable between Iceland and the UK in order to explore the arbitrage possibility, which provides a thorough account of the value of the adaptability of Icelandic hydropower. There are two interlinked issues in hydropower scheduling: i) determination of the water value; and ii) optimal bidding into the day-ahead marked conditional upon the water value, which are identified theoretically. A conceptual solution using stochastic dynamic programming is provided and is supported by a simplified version of the problem along the lines of a battery problem (i.e., a given storage with a stochastic inflow and fixed domestic demand interacting with the UK market through a day-ahead auction).

The study concludes that building a 900 MW subsea power cable between Iceland and the UK would significantly increase electricity production in Iceland due to higher prices. This would result in a considerable redistribution of welfare from consumers to producers, and an increase in welfare in the country's energy sector by €64 million a year, compared to no cable being installed. In addition, the connection to cheap green power supplies is beneficial to the UK, where the economic welfare would increase by €41 million per year for a 900 MW cable in contrast to a scenario where there is no cable. Moreover, there is an increase in the total economic welfare of both countries when there is a higher investment resulting in a 1471 MW cable, together with an increase in the total producer and consumer surplus in both countries.

Table of Contents

List of Figures

List of Tables

Chapter 1 - Introduction

Iceland is a Nordic country rich in renewable energy, but with few natural resources; therefore it is imperative to make effective use of the limited natural resources available in the country. A power cable between Iceland and Britain has been suggested, with the first proposal to connect Iceland´s grid with that of Scotland, via a subsea cable occurring over 60 years ago. The viability of such a project has been regularly evaluated over the last 30 years, and historically, the results have shown that while such a project would be technically possible, it would not be a profitable endeavour (Landsvirkjun, 2016b). This research focuses on the economic feasibility of such an investment.

1.1 The Problem

As highlighted by Jón Steinsson, an Associate Professor of Economics at Columbia University, in an interview broadcast on the Icelandic radio station Bylgjan on February 6th 2015, Iceland could be as rich as Norway, or even richer, if it fully maximises its resources to generate substantial revenues. Steinsson noted that Iceland is not currently maximising economic yields from renewable energy sources. Currently, the emphasis in Iceland appears to be on job creation, rather than directly realising the value of the natural resources. Iceland has valuable energy contained in its rivers, but instead of focusing on mining gold, the country appears to be side-tracked by the idea of creating jobs through building and running aluminium smelters, rather than selling the gold/energy directly. Iceland needs to reconsider its pricing strategies, which should reflect the true value of the country's resources. One solution would be to export electricity from Iceland to the UK through a subsea power cable, which according to Steinsson, would lead to higher electricity prices. Moreover, it provides an export opportunity for the surplus energy that has not been utilised as a result of economic limitations (Eyjan.pressan.is, 2015).

Ola Borten Moe, former Energy and Petroleum Minister of Norway, attended an open meeting in Iceland on 9th September 2014 to discuss the restructuring processes occurring within the Norwegian market for electric power and experience related to European electricity market integration. According to Moe, the deregulation and liberalisation of the Norwegian electricity sector in 1990 has had a significant impact on Norwegian society. In this context, he highlighted that Norway's experience demonstrates that interconnection has enhanced market efficiency due to greater security in the supply of electricity. This has been valuable for Norway in dry periods, as the country has been able to sell electricity when the price was high, thereby enhancing the total value created. In other words, there has been a more efficient energy market and improved energy security (Askja Energy Partners, 2014c).

Liberalising international trade can yield important economic benefits. In an interview with Icelandic weekly, Viðskipablaðið, on 26th February 2013, Marius Holm Rennesund, a Norwegian economist from Thema Consulting in Norway, noted that, with a sub-sea electrical cable connection from Iceland to Europe the electricity price would increase more than it did in Norway, primarily because the Icelandic market is smaller and the cable is larger (Evans, 2002; Viðskiptablaðið, 2013). This concept requires a thorough investigation to determine whether building a subsea power cable between Iceland and the UK is feasible, and to investigate the benefits associated with the international liberalisation of Iceland's electricity market.

Chapter 2 - Background to the Topic

2.1 Iceland

2.1.1 History

Electricity was first generated in Iceland in 1899, and the first hydropower turbine began operation in 1904. The hydro project in Reykjavik was initiated by a public utility firm, Rafmagnsveita Reykjavíkur, which today is known as Orkuveita Reykjavíkur (OR) (Askja Energy, 2015). In subsequent years, many power plants were constructed, and by 1934 there were 38 operational power stations with a total installed electrical capacity close to 5 MW. These were mostly hydropower stations, but some were kerosene-fuelled.

The first decade of the 20th century marked the beginning of geothermal energy utilisation in Iceland. For centuries Icelanders had relied on geothermal water for bathing and washing; however, the first use of geothermal energy to heat houses can be attributed to Stefán B. Jónsson, who laid a pipe to his farm in 1908 (Iceland Geothermal Cluster Initiative, 2015; Lúthersson, n.d.; Thordarson, 2008). The first successful geothermal electric power station was installed in Bjarnaflug and this came into operation in 1969 with a capacity of 3 MW (National Energy Authority, 2006). At this time, the government and municipalities around the country managed the electrification of Iceland; however, they were incapable of financing new energy projects. Thus, Landsvirkjun was founded on 1st July 1965 in order to optimise the exploitation of natural energy resources and to encourage foreign direct investment (FDI) in power intensive industries in Iceland (Landsvirkjun, n.d.), and Iceland followed Norway's footsteps by exporting power in the form of aluminium (Hreinsson, 2008; National Energy Authority of Iceland et al., 2016). Since then, the utilisation of geothermal and hydropower has grown gradually in response to the rapid growth in the energy-intensive industrial sector. Figure 1 and Figure 2 show the rapid growth of electricity generation capacity in recent decades.

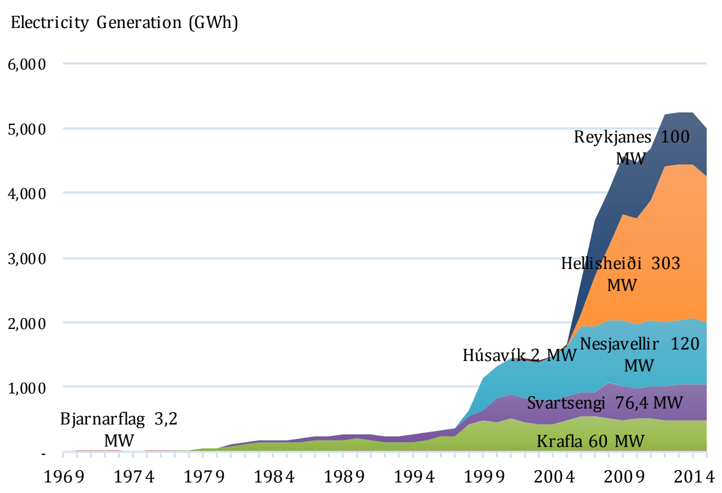

Figure 1: Electricity generation by geothermal power plants 1969-2015
(National Energy Authority of Iceland, 2016)

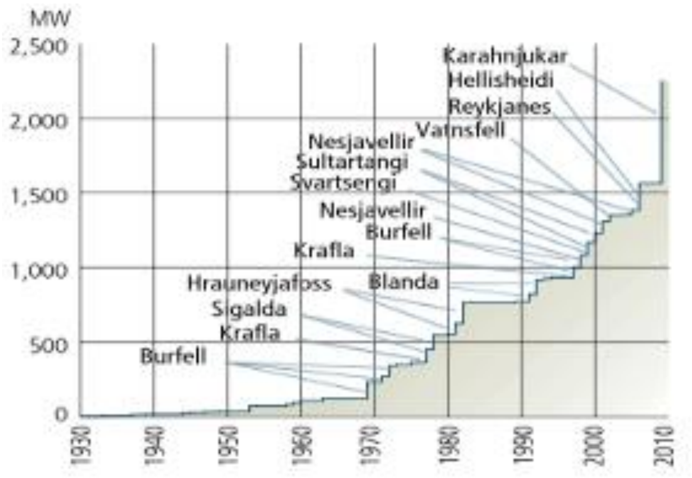

Figure 2: Total installed hydro and geothermal capacity in Iceland
(National Energy Authority, 2006)

The electricity market has evolved in a natural monopolistic way, given Landsvirkjun's dominant position; in other words, Landsvirkjun owned and operated nearly all the transmission systems and had exclusive rights to sell electricity to energy intensive industries. Meanwhile, other electricity power companies managed the distribution system and sold electricity to end-users, whilst simultaneously being involved in other activities, such as small-scale electricity production and the distribution of hot and cold water.

In 2003 the Electricity Act resulted in a market-based regime by opening the Icelandic electricity market to free competition regarding generation and supply, although there was only one transmission company and a local monopoly for distributors. The first step was to separate production and transmission within Landsvirkjun, and in 2005, Landsnet was established to operate Iceland's electricity transmission system and to manage its system operations.

Landsnet established transmission system operator (TSO) network charges, but the regulator, the National Energy Authority (NEA) has to approve these charges. The NEA also supervises other aspects, including pricing, quality and security of supply (EFTA Surveillance Authority, 2014; Energy Market Authority, 2013; Landsnet, n.d.-a, n.d.-b; Ólafsson, Þorsteinsson, Pétursdóttir, & Eggertsson, 2011).

2.1.2 Market Structure

2.1.2.1 Production

Almost all electricity in Iceland comes from renewable sources and in 2014 hydropower was Iceland´s biggest energy supplier, providing approximately 71.03% of the total supply, while 28.91% came from geothermal, 0.05% from wind power, and only 0.01% from fuel-run generators. The total generation in 2014 in Iceland was approximately 18.1 TWh, and it is estimated that Iceland has the potential for an additional 35 TWh of renewable energy (Nation Energy Authority of Iceland et al., 2016; National Energy Authority, 2015a). According to the data, Iceland is the world´s largest electricity producer per capita (i.e. 55.6 MWh in 2014), and this has increased in recent years due to heavy industrial activity (Iceland Review, 2016; National Energy Authority of Iceland, 2015b).

There are three major producers of electricity in Iceland, the national power company, Landsvirkjun (12.810 GWh), On Power (3.443 GWh)[1], and HS Orka (1.337 GWh) (Figure 3). These companies are all publicly owned, except for HS Orka, which is owned by Magma Energy Sweden, A.B and Jarðvami slhf.

[1] On Power is a subsidiary of Reykjavik Energy and took over the production and sale of electricity on 1st January 2014.

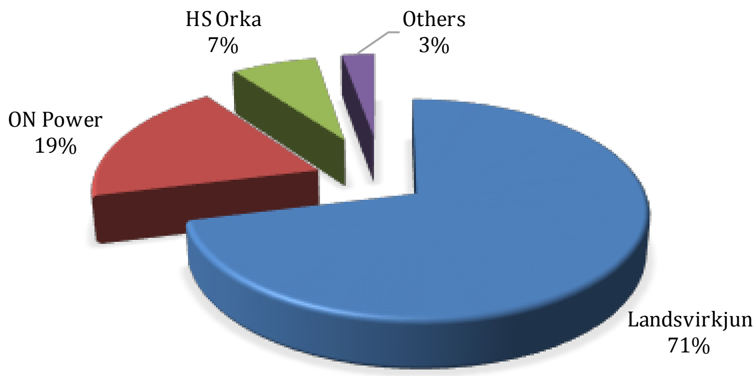

Figure 3: Electricity generation by energy companies
(Hörður Arnarson, 2014)

The three largest companies generate 97% of the total electricity and are active in the wholesale market. Smaller producers either sell directly to their own retail division or enter a 7-10 year contract with retail sales companies. The electricity market is open for all users to select a sales company. Landsvirkjun is only active in the wholesale market for electricity, where its competitors are Orka Náttúrunnar (On Power) and HS Orka. Wholesale accounts for 20% of Landsvirkjun's volume and industry 80% (Hordur Arnarson & Larusson, 2016; EFTA Surveillance Authority, 2014; National Energy Authority of Iceland et al., 2016).

2.1.2.2 Consumption

Although Iceland once depended on coal, and later on oil, for heating, geothermal energy is currently responsible for about 90% of all space heating in the country. The share of geothermal in the primary energy supply of Iceland is roughly 68%, and Figure 4 shows the estimated utilisation of geothermal energy in Iceland for 2014 by category. Swimming pools, snow melting, industry, greenhouses and fish farming are all sectors which utilise geothermal energy (Ragnarsson, 2015). However, oil is still essential for fuelling cars and the country's fishing fleet (Íslandbanki, 2010).

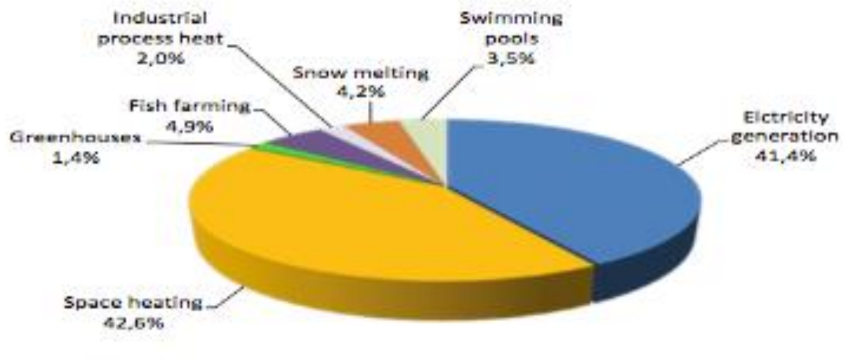

Figure 4: Utilisation of geothermal energy in Iceland in 2014
(Ragnarsson, 2015)

Icelandic electricity consumption is mainly divided between heavy industry and general use. In 2014, energy intensive industries used around 79% of all electricity produced in Iceland, while other industries consumed less power. For the most part, electricity supplied to Icelandic homes accounts for around 5% of total electricity use (Jónsson, Bjarnason, Hannesson, Davies, & Martin, 2016).

Consumers typically buy electricity from suppliers based on a prior electricity supply contract, while suppliers sell electricity to end-users, either that they have generated or by purchasing electricity on the open market and later re-selling it. In the latter case, electricity is traded through bilateral contracts between generators and electricity suppliers. The electricity price paid by the consumer reflects both the direct costs of generation and transmission cost (Landsnet, n.d.-d). Figure 5 and Figure 6 show the average wholesale price and average price to industries in Iceland. Prices to industry have somewhat decreased, while the wholesale price has been relatively stable. More generally, industry prices depend on long-term fixed contracts directly held with a power generator, as industries are usually heavy consumers.

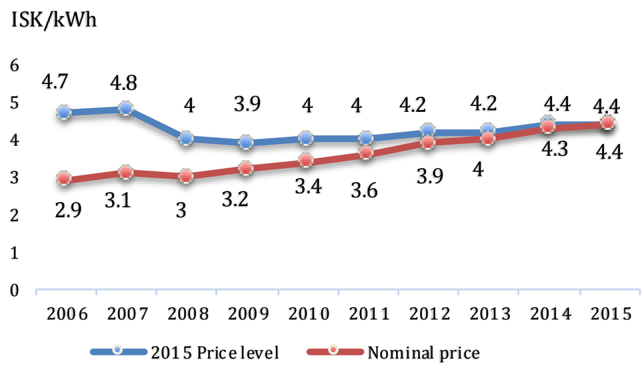

Figure 5: Average price to industry including transmission
(Hordur Arnarson & Larusson, 2016)

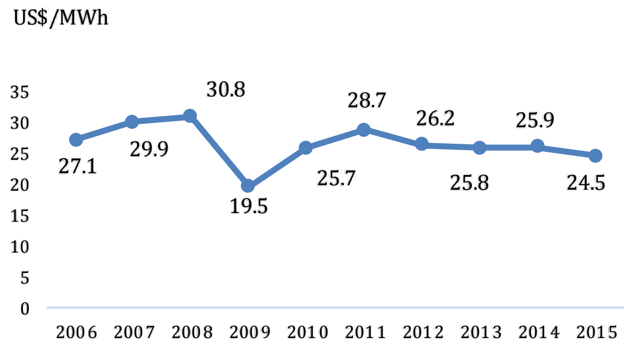

Figure 6: Average wholesale price
(Hordur Arnarson & Larusson, 2016)

In recent years Landsvirkjun has canvassed for a decoupling of electricity prices from the aluminium price, in order to better reflect trends in international markets. Thus in accordance with new pricing strategies, revenue from power sales has started to decouple from aluminium prices. New contracts and an increase in sales are not linked to aluminium prices, for example on 13th May 2016, Landsvirkjun and Norðurál Grundartangi ehf reached an agreement on terms to extend the company's 161 MW power contract which is linked to the market price for power within the Nord Pool power market. In this context it is worth mentioning that today, a third of agreements is linked to aluminium prices, compared to two-thirds in 2009 (Hörður Arnarson, 2016; Ásgeirsdóttir, 2011; Landsvirkjun, 2016a; Moody´s, 2015).

2.1.2.3 Distribution

As previously mentioned, Landsnet operates the only transmission system in Iceland, even though there are many distribution systems. The transmission system operates at a voltage between 30kv and 220kv. Power intensive-industries, i.e. those where a single location uses not less than 14 MW of power and utilises this power for 8,000 hours/year, are connected directly to the transmission grid. Local distribution companies receive power from Landsnet's grid and deliver power through their own distribution network to the end consumer (Ásgeirsdóttir, 2011; Landsnet, n.d.-c).

2.2 The United Kingdom

2.2.1 UK Electricity Market Structure

The British electricity market was liberalised in the early 1990s, and before the New Electricity Trading Arrangement (NETA) was implemented in March 2001, there was a pool structure market, i.e. all trade in electrical energy occurred via the pool, and were placed on a merit order to meet the projected demand with the bids that generators presented. This was a day-ahead market, with the system operator admitting or refusing bids for the sake of matching the estimated demand with the bids that the generators had provided. Every generator received the same price for their electricity, indifferent of their bid price, which in fact was defined by the highest-priced bid that had been approved (Barbour et al., 2016). Thus, NETA was initiated and this introduced bilateral and voluntary forward trading in England and Wales, to adjust the compulsory auction pool that had been in place since 1990. In April 2005, the British Electricity Trading Arrangement and Transmission Arrangement (BETTA) extended this to include Scotland, and in the same year the European Union (EU) carbon emission market commenced. In particular, the composition of the altered market hinged on thoroughly liberalised relations, where the majority of energy trading takes place in forward contracts (Bunn, Andresen, Chen, Westgaard, & Place, 2012).

In the UK's deregulated electricity market, the transmission and distribution networks are monopolies excluded from regulation by the Office of Gas and Electricity Markets (OFGEM). The TSO, National Grid, secures a functioning market by ensuring that supply and demand are balanced in the short term. BETTA specifies the market rules that determine how the generator and suppliers interact with the market. The market consists of four distinct elements that promote the trading of electricity: the forward market, power exchange, balancing market, and reserve market. Every day is divided into 48 ×30min periods, including one long day (50 periods) and one short day (46 periods) to account for daylight savings (Barbour, 2013).

The wholesale market is a centralised power market where power suppliers sell through a power exchange and wholesale prices are contingent on the market conditions, and its role is the generation of a transparent and reliable reference price. In general, the power exchange matches the bids and offers that buyers and sellers of electrical energy have submitted by using either predefined blocks, electrical energy, or other ‘products’. In the UK, these so-called weightings and their clarification are defined and can be adjusted by the Imbalance and Settlement Group, in order to better mirror market conditions or for desired outcomes in terms of the reference prices (Barbour et al., 2016).

The main reference for spot trading in the British market will now be briefly considered. The predominant reference for spot trading has been the UKPX, the UK-based power-trading platform, now called APX Power UK. The spot price, i.e. volume-weighted average price (VWAP), is an intra-day calculation that reflects all trades one day in advance. In other words, the spot prices that represent volume-weighted averages are ahead of each trading period. Transactions on the UKPX power-trading platform first took place in March 2001 (Bunn et al., 2012) and in 2009/2010 Nord Pool and the N2EX market initiative commenced (Solibakke, 2011). The N2EX platform was set up to primarily enhance exchange-based trading and the platform also set out to list cash-settled power futures contracts for the British market (Füss, Mahringer, & Prokopczuk, 2015). Furthermore, it is worth noting that the UK electricity-trading scheme does not employ the locational marginal pricing scheme and congestion (Bunn et al., 2012).

To capture the fundamental trading concept of a power-trading platform, how the exchange market operates as a place for trading and clearing will be considered. On the edge of the physical delivery, agents make small adjustment to their position, from blocks for peak and base load to half-hourly resolutions. These are conducted moderately up to 1 hour prior to each-hourly physical delivery period, i.e. points that are interpreted as gate closures, and are effectively the spot markets. Following gate closure, in particular the deadline for trading electricity to be delivered in this specific period, the system operator supervises a market for system balancing, and reconciles offers and bids for load increases or decreases, which resembles an auction in real-time trading (Bunn et al., 2012).

Since the adoption of the NETA initiative, wholesale trading in the British market is chiefly distinguished by over-the-counter (OTC) forward transactions, a forward contract with physical delivery for electrical power supply. This OTC market where the forward contract for purchase or sale contain maturities from the day-ahead up to several years ahead of delivery, provides around 90% of the total electricity volume traded in the UK (Füss et al., 2015).

2.2.2 UK Renewable Energy Policy

In 2007 the British government agreed to the European 20-20-20 targets, which sets three climate and energy policy goals to be realised by 2020. This included a 20% share of EU energy from renewables, reducing greenhouse gas (GHG) emissions by at least 20% (measured against emissions during 1990), and moving towards a 20% increase in energy efficiency (Eurostat, 2014; Geels et al., 2016). Thereafter, in November 2008 the UK Parliament passed the world's first Climate Change Act, which established a legally binding national action plan for reducing GHG emissions. The Act legally committed the UK to cut GHG emissions by 80% by 2050 compared to 1990 emissions (Lockwood, 2013).

In 2008, the British government, established the Department of Energy and Climate Change (DECC) and the independent Committee on Climate Change (CCC) which is responsible for presenting pathways through which the UK can achieve its climate targets (Geels et al., 2016). Following this, the DECC published a Renewable Energy Strategy in 2009, which aimed for 30% renewable electricity use by 2020, together with 12% of heat and 10% of transport energy, in order to meet the relevant EU targets. It is expected that in order for the targets to be met, especially the requirements concerning decarbonisation, a tight domestic policy is needed along with strong pressure to buy renewable electricity and carbon dioxide permits from abroad (Pollitt, 2010).

It is worth noting that the UK has made some progress regarding the integration of renewables into power generation, with an increase from 1.9% to 19.1% between 1990 and 2014 (Geels et al., 2016). Figure 7 shows UK electricity generation by source in 2015. The total electricity generated in the UK was 337.7 TWh, with approximately 54.5% generated from coal, gas and oil, and 20.8% nuclear power (Department of Energy and Climate Change, 2016).

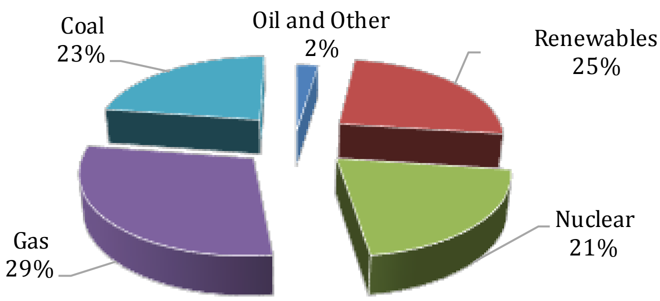

Figure 7: UK electricity generation by source 2015
(Department of Energy and Climate Change, 2016)

As stated in the DECC's 2011 Carbon Plan, it is essential that the UK greatly increases its energy efficiency and decarbonises electricity via renewable and nuclear power, together with carbon capture and storage, in order to meet the UK climate change targets as set out in the Climate Change Act 2008 (Geels et al., 2016).

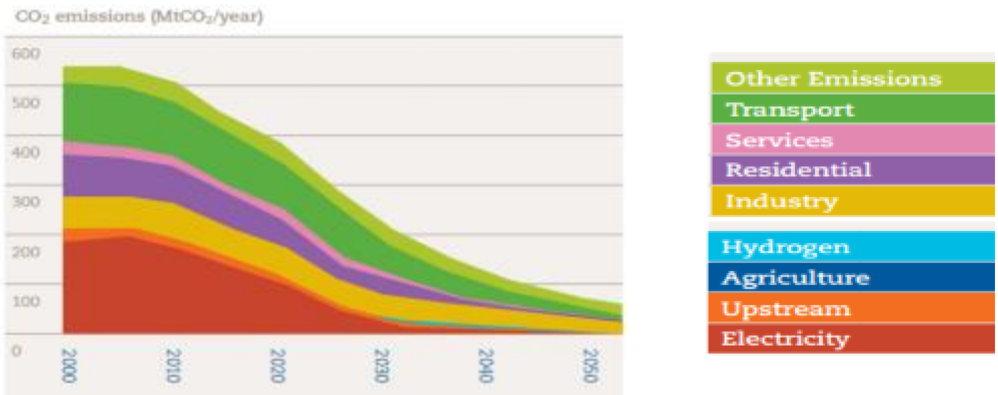

Figure 8: Projected UK carbon emissions for a 90% cut by 2050 relative to 1990 levels (Ekins, Strachan, & Usher, 2013a)

According to one report, *The UK energy system in 2050: Comparing Low-Carbon, Resilient Scenarios,* in order to meet the GHG emission target for 2050 in a cost effective manner, there is a need to cut 80% of GHG emissions by 2030 within the UK electricity system. Furthermore, as Figure 8 shows, due to a lack of a clear price signal, the electricity sector, with a considerable amount of conventional coal-fired power plants, is the largest source of carbon dioxide emissions. Hence, as previously mentioned, in order to meet the UK's climate change targets, electricity needs to be decarbonised, while gas use in heating and petrol/diesel in cars potentially replaced (Ekins, Strachan, & Usher, 2013b).

2.3 Possible Benefit of an Interconnector

International electricity trade between Iceland and the UK via a subsea cable is driven by price differentiation. Electricity trade from a low-price country (Iceland) to a high-price country (UK) will increase prices in the former. However, the Icelandic electricity market is relatively small compared to the UK market. Thus, it is likely that electricity interconnection between the two countries will have little impact on electricity prices in the UK. The differences in electricity prices in Iceland and the UK will most likely reflect bottlenecks in the transmission process.

The interconnection arising from price differentiation between the UK and the Icelandic market essentially consists of both productive and allocative efficiency. Electricity generation costs in Iceland are low and connecting Iceland's isolated energy system to another market may enhance generation efficiency; in other words, a subsea cable stimulates use of the cheapest method of generation. If the UK's marginal cost of generating electricity is higher than the relevant cost in Iceland, then producing one additional unit in Iceland instead of in the UK will increase efficiency in electric power generation and utilisation.

There would also be allocative efficiency if some of the electricity consumption was allocated from consumers paying a low price to consumers paying a higher price, because these latter consumers have a higher marginal utility of electricity consumption. However with a relatively low price, there is elasticity in demand, which means that the price change in quantity is low for the percentage change in price, and consequently, the allocative benefits of the interconnection will not be large (Giesbertz & Mulder, 2008; Hagfræðistofnun Háskóla Íslands, 2013; Valeri, 2009).

A subsea power cable between Iceland and the UK will offer Iceland access to a market which is willing to pay a significantly higher price for electricity than the power intensive industry within Iceland. Andrew Higgins stated in an article in The New York Times that in 2011 Landsvirkjun received on average less than $30 per megawatt, which is less than half the rate in the EU (Higgins, 2013).

The benefit from an interconnector that combines electricity markets may translate to savings in one or more of the following areas:

- Benefits from deferral of investment in generation.
- A reduction in unserved energy that can be evaluated by the economic value of the lost load.
- A reduction in fuel and other variable operating costs by using a method that is more efficient for generating power, thereby being more beneficial for those who have access to the most efficient generating options.
- A reduction in costs e.g. spinning reserve and frequency control (Turvey, 2006).

Figure 9 shows the welfare implications of an interconnector. In this figure the total demand of the two countries is shown for one specific situation. The supply is illustrated by the curves C^A and C^B, which are different in shapes, and it is assumed that demand is fixed, i.e. unresponsive to price. Assuming that both countries supply their own load, a substantial difference in the marginal generation cost emerges, which is noted as P^{Ao} and P^{Bo}, respectively. From one point of view, trading electricity across borders (between the two countries) with no restrictions would result in a homogenous price in both zones, represented by p^*. As expected, this could only occur where there is no congestion, i.e. when there is sufficient transport capacity for transmitting electricity. The bottom line is that there is a theoretical welfare loss in the height of the area ADE, because the overall generation costs are higher in theory (Spiecker, Vogel, & Weber, 2013).

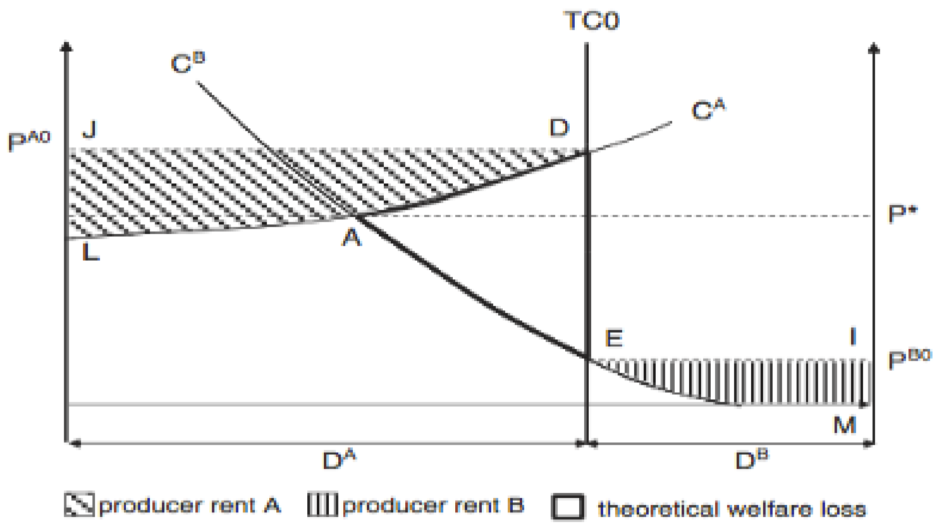

Figure 9: Welfare implications of an interconnector
(Spiecker et al., 2013)

2.4 The Criteria

The Institute of Economics Studies in Iceland conducted research on the macroeconomic effect of an undersea cable between Iceland and UK in cooperation with Landsvirkjun (the biggest energy company in Iceland), and published their findings in May 2013. The criteria regarding power development that follow are based on the key outcomes of that research.

2.4.1 Power Cable and Converter Stations

1. Preparation and construction works takes eight years; generally, the first three years are devoted to preparation, while subsea cable laying work five years. Converter stations are constructed in the final three years of the construction period.[2]
2. Expenditure relating to the preparation is € 20-50 million at the price level of 2013, of which domestic expenditure is 22.5%.
3. The subsea cable and converter stations are entirely financed by foreign investors. Only the converter station that is located in Iceland is a domestic investment and is considered as domestic spending. It is expected that 50% of the investment would be used for import.
4. The subsea cable is 700-900 MW and 1000-1200 km long.
5. Annual operating and maintenance costs due to the cable are 1.75% of the construction expenditure, largely because the converter station is located in Iceland.

2.4.2 Power Plants

1. It is necessary to build plants to produce 3 TWh of electricity per year for the project; a hydropower plant will generate 0.75 TWh, a geothermal plant 1.5 TWh and windmills 0.75 TWh.
2. The construction cost is from US$ 2.5 to 3.1 million at the 2013 price level of per MW of installed power for a hydropower plant, US$ 2.6 to 3.2 million for a geothermal plant, and US$ 1.35 to 1.65 for the windmills.
3. The utilisation time of the hydropower plant is 79%, geothermal plant 94%, and windmills 45%.
4. About 40% of the construction expenditure of a hydropower plant goes into import, 60% into a geothermal plant and 80% for windmills.
5. It takes four years to build hydropower and geothermal power plants and the construction expenditure is distributed evenly over the last four years of the

---

[2] Electricity is supplied to costumers as alternating current (AC), but this is not efficient over long distances and energy is lost in transmission. To avoid this, power is carried through the interconnector as direct current (DC) and land based converter stations are constructed at each end of the high voltage DC cable to convert power between AC and DC.

construction period. It generally takes two years to build windmills, and the expenditure is distributed evenly over the last two years of the construction period.

6. The annual operating and maintenance costs of a hydropower plant is 3.5% per year of the construction expenditure, 6% for a geothermal power plant, and 8% for a wind power plant, while 10% of the expenditure goes into import.

2.4.3 Electric Power Transmission

1. Expenditure for electric power transmission, which will occur simultaneously with laying of the subsea cable, is ISK 20-60 billion at the price level of 2013.
2. Annual operating and maintenance costs of the transmission are 1.75% of the expenditure.
3. Net export of electricity through the interconnector will be 5 TWh per year on average, since 3 TWh comes from the new power plants and 2 TWh is obtained by using untapped energy in the system. It is expected that 0.4 TWh would be lost in transmission (Hagfræðistofnun Háskóla Íslands, 2013).

Chapter 3 - Literature Review

The first proposition to connect Iceland's electricity grid with Scotland through a subsea power cable was introduced over 60 years ago, and the feasibility of constructing a subsea power cable between Iceland and the UK has been regularly evaluated over the last 30 years (Landsvirkjun, 2016c). Efforts to estimate the feasibility via a framework of dynamic programming has however, to the author's knowledge, not been undertaken.

In 2013 an advisory group was initiated by the Icelandic Minister of Commerce and Industry to thoroughly examine the socio-economic features of a subsea power cable, together with technical, environmental and legal aspects. The group delivered a report that captured the key socio-economic aspects of a subsea cable, and stated that the projected cable could be feasible, although uncertainties remained (National Energy Authority of Iceland et al., 2016).

In January 2016 Iceland's Minister of Industry and Commerce, Ragneiður Elín Árnadóttir, presented a fresh report detailing the projected North Atlantic Energy Network (NEAN) at the Artic Frontiers Conference in Tromsø, Norway. The report generally sought to investigate the possibility of connecting isolated energy systems in the Artic, Nordic and northern European regions to the UK and the broader European continent, which is a significantly larger energy market. The main feature of the report was that there are unrealised sustainable energy potentials within North Atlantic countries, including hydro, wind, geothermal and solar power. Nonetheless, further research is required in order to map the total supply of sustainable energy across this vast area (The Artic University of Norway, 2016).

3.1 Brief Review of Interconnector Studies

De Nooij (2011) performed a cost-benefit analysis (CBA) of building an interconnector (NorNed and the East-West interconnector) in Europe. CBA can be defined as the process of quantifying the cost and benefits of a project in order to have a single scale of comparison enabling an unbiased valuation. In addition, a CBA evaluates the net present value of a choice by discounting the future cash flow of an investment. The result of the analysis by De Nooij (2011) is that current interconnector and transmission investment decisions in Europe may not maximise social welfare.

The arguments advanced by De Nooij will be briefly considered. First, the extent of the demand for transmission capacity and interconnectors is relatively unknown; hence, the benefits of investment are uncertain. Second, both the analyses underlying the investment decision to build an interconnector, i.e. NorNed (between the Netherlands and Norway) and East-West (between Ireland and the UK), do not take the resulting changes in generator investment plans into account and ignore the likely benefits of increased competition. In other words, the trade and competition benefits can increase allocative efficiency and productive efficiency in the short term. Moreover, competition may reduce cross-inefficiency, namely where firms could produce at a lower cost than they actually do. Third, interconnector decisions receive the highest attention while more money goes to transmission investments. More specifically, this paper investigates the keystone of investment decisions in interconnectors in more detail, using CBA as a benchmark. Accordingly, relevant lessons are drawn, and two recommendation for future improvements are developed (BusinessDictionary, n.d.; De Nooij, 2011).

Edmunds et al. (2014) examined the technical benefits of additional energy storage and interconnections in a future UK electricity system. The reference model of the UK electricity system was developed using the EnergyPLAN tool and it is, a deterministic hourly simulation model that optimises the operation of the system and allows for a choice of regulation strategies to be explored. This model was tested against real data which revealed that the model accurately represented the UK electricity system. This working paper examined four scenarios in a technical analysis for the years 2020 and 2030, each one calculating the maximum technically feasible wind penetration. Furthermore, the level of interconnection and energy storage was modified in order to evaluate the technical benefits to the process of a 2030 UK electricity system. Edmunds et al. (2014) found that boosting levels of interconnection and energy storage allowed for a further reduction in the primary energy supply. It also increased the maximum technically feasible wind penetration, which in turn reduced the intensity of system emissions, namely from 483 gCO_2/kWh in 2012 to 113 gCO_2/kWh in 2030. Moreover, boosting the levels of interconnection and energy storage provided technical benefits in the potentially forthcoming UK system (Edmunds, Cockerill, Foxon, Ingham, & Pourkashanian, 2014).

Spiecker et al. (2013) studied the benefits of additional line extensions between the European mainland and northern European countries. They used an efficiently computable stochastic European electricity marked model (E2M2s) covering 30 European countries which estimated the quantification of the economic effects of limited transmission capacities and their extension. The authors evaluated the welfare and distribution effects among market agents within a business as usual scenario up to 2030.

The model proposed by Spiecker et al. (2013) provides evidence that wind integration requires the development of additional interconnection capacities. Moreover, the authors found that stochastic wind and hydro power generation increased the value of grid expansion more than in the deterministic scenario. This reveals that grid extension could increase system flexibility and help in mixing renewables. Perhaps the most interesting feature of this paper is the analysis of grid expansion to integrate renewables from an economic-welfare perspective. This setup allows measures of allocative efficiency, as well as capturing the underlying dynamics of renewable energy production (Phan & Roques, 2015; Salo, 2015; Spiecker et al., 2013; Zerrahn & Huppmann, 2014).

Diffney et al. (2009) estimated the cost of increasing the share of wind within the Irish energy mix, to mirror the policy target of 40% electricity from renewables by 2020. An analysis was performed assuming various scenarios based on fuel and carbon-dioxide permit prices and the extent of electricity interconnection within the UK. In their study, a simulation based optimal dispatch model for the all-island (Ireland) wholesale electricity market was developed as a mandatory pool market with capacity payments. In addition, within every half-hour generation had to match demand, determined by an exogenous demand curve that is assumed to be price inelastic. A similar model was set up for the UK in order to analyse the effects of an interconnection. A key underlying assumption was that the wholesale market in the UK was managed by the same regulation as in Ireland, including a mandatory wholesale market where generators bid their short-run marginal cost of production.

The analysis led to curious conclusions, whereby investment in large amounts of wind generation was only feasible if there was investment in an interconnection that was equivalent in scale. In other words, a new interconnection line would allow the wind to generate power whenever it was available, rather than being restrained at times of low demand or bringing the extra costs of ramp-up/ramp-down of thermal plants. This indicates that the total capital costs associated with an investment in high wind generation would be considerable. Thus, it is particularly important to focus on minimising the cost of this investment in order to reduce the cost of the system to consumer policies (Diffney, Gerald, & Valeri, 2009; Wilson, 2014).

3.2 Research Question and Hypothesis

This study seeks to understand the relevant factors to be taken into consideration when the feasibility of the project is reviewed and compared to other possibilities regarding the utilisation of natural resources in Iceland. Accordingly, the following research questions and hypothesis will be considered:

I) How will an interconnector affect relevant prices in Iceland?

II) What is the economic benefit of selling electricity through a subsea cable, compared to selling electricity to domestic manufacturers?

III) How will an interconnector affect different types of electricity production in Iceland?

Hypothesis:

- Electricity prices in Iceland will be higher following the construction of an interconnector.

Chapter 4 - Data and Methods

The analysis is based on two markets, a combined market (based on geothermal energy and hydropower in Iceland) and another combined market (based on gas, coal, nuclear power, wind bioenergy, hydroelectric, solar, oil and others in the UK) (Department of Energy and Climate Change, 2016).

The numerical model LIBEMOD is used to determine the actual price effect from an interconnector and to analyse the economic benefit of selling electricity through a subsea cable, in comparison to selling electricity to domestic manufacturers in Iceland. The model accounts for total energy produced and total energy consumed in each of the 30 European model countries (EU-30, the 27 countries of the EU plus Iceland, Norway and Switzerland). There is also a competitive supply of all fuels and energy, as well as demand for all forms of energy from four end-user groups, i.e. household, industry, transport, and the service sector, within each model country. The simulation used in this thesis was run by the LIBEMOD project team (Frischsenteret, n.d.).

Estimated electricity consumption data from Iceland are used for the period 2015-2050 from the Icelandic Energy Forecasts Committee. The data are divided into firm and secondary transmission, and shows an estimated low forecast, main forecast and high forecast (National Energy Authority of Iceland, 2015c). Code in Julia, a freely available open-source programming language (http://julialang.org) is utilised to simulate the effect resulting from the daily arbitrage between the two markets. The simulations are based on a given storage with a stochastic inflow and fixed domestic demand interacting with the UK market through a day-ahead auction.

Data will be collected from a digest of UK energy statistics (Dukes), which is the key source of energy information in the UK. The statistics also contain a complete picture of energy production and energy use over the last five years, with the main series going back to 1970 (Department of Energy and Climate Change, 2013).

The electricity prices used in the second model to generate the typical daily electricity prices in the UK are volume-weighted reference prices for each half-hourly period, and are for the period 01.01.2003 to 09.05.2016. The prices retrieved from the APX power exchange are freely available (www.apxgroup.com). However, it should be highlighted, that, volume-weighting is carried out for three types of contract, half-hourly, two-hour-block, and four-hour-block contracts (Maciejowska, Nowotarski, & Weron, 2014). The inflow data for the second model is based on the period 1984-2004 with weekly inflow into Landsvirkjun´s reservoir.

The electricity price used in the simplified version of the second model were retrieved from the N2EX day-ahead market, i.e. Nord Pool´s UK power market (Nord Pool, n.d.). The electricity prices are hourly reference prices from the day-ahead auction market for the period 06.02.2014 to 09.07.2016. The prices retrieved from the Nord Pool´s UK power market are freely available (www.nordpoolspot.com)

Data was collected from the Icelandic National Energy Agency (NEA), which is a government agency under the Ministry of Industries and from Statistics Iceland. The Icelandic NEA gathers data on production, import, use and price of energy and other relevant sectors (Authority), n.d.). Statistics Iceland provides information about installed capacity and generation in public power plants (1904-2014), gross energy consumption by source (1987-2014), gross consumption of electricity (1990-2014), electricity use (1998 – 2014), oil use (1983 -2014), prices of various energy forms (1980-2012), and overall energy balance (1983-2006) (Hagstofa Íslands, n.d.).

Chapter 5 - LIBEMOD

5.1 Description of the Numerical Model LIBEMOD

LIBEMOD concentrates on the choice of investors, producers, traders and consumers (Aune, Golombek, Moe, & Rosendahl, 2015). The LIBEMOD model can be described as a combination of the bottom-up and top-down modelling traditions, as it offers a detailed description of electricity and natural gas trading in an integrated European market, using gas pipelines and electricity transmission lines that connect the model countries.[3] The model also has a strong academic foundation in economic theory, through formulating behavioural relations from well-defined optimisation problems together with the requirement that markets should clear (Frischsenteret, n.d.; Golombek, Kittelsen, & Rosendahl, 2012).

The model defines six other goods besides natural gas and electricity, which are oil, three types of coal, and two types of bioenergy, which are extracted, produced, traded and consumed in each of the EU-30 countries. Each market for energy goods is expected to be competitive in 2030. In terms of equilibrium, all arbitrage opportunities are exploited in such a way that price differences for each good reflect cost differences only.

When considering the trading of energy goods within LIBEMOD, steam coal, coking coal and biofuel are traded worldwide, while natural gas, electricity and biomass are traded within European markets, although these goods are also imported from non-European countries.

5.1.1 Consumer Choice

Generally, each individual country transports all types of energies to all types of energy consumers (e.g. industry, transportation and electricity generation), which is modelled by a constant unit cost that varies between consumers of energy and energy goods. The demand from each type of end-user stems from a nested CES utility function,

[3] These networks are designed with pre-existing capcities for the data year of the model, although profitable investements capacities can be expanded (Aune, Golombek, & Tissier, 2015).

while the demand from electricity generation is derived from an optimisation problem of an electricity supplier (Aune, Golombek, Moe, et al., 2015).

The aforementioned nested CES utility function has five levels. First, at the so-called top-nest level, there is an opportunity for substitution, in particular, between energy related goods and other forms of consumption. Second, the end-user is opposing a trade-off between uses that depend on different sources of energy. Moreover, each of this is a nest describing the complementary relationship between a specific energy source and an item, e.g. electricity and light bulb. Finally, at the fourth and fifth levels there are special electricity characteristics to determine the possibility for substitution, i.e. seasons (summer and winter) and day and night.

The share and substitution parameters in the CES tree are calibrated to minimise the deviation from the target own-price and cross-price elasticities. Furthermore, the target cross-price elasticity in each season between electricity in the two periods of the 24-hour cycle are evaluated at 0.2 and the target cross price elasticity is replicated at 1.5 between coking coal, lignite and steam coal (Frischsenteret, 2014).

Furthermore, apart from electricity, energy goods are traded on annual markets. However, it is however worth noting that calibrated parameters of the utility function differ between end users and countries (Golombek, Arne, & Kittelsen, 2013).

5.1.2 Prices and Quantities

LIBEMOD determines the relevant prices and quantities within the European energy industry,[4] together with prices and quantities of energy goods traded worldwide. Base year prices and taxes are taken from IEA Energy Prices and Taxes (2011a and 2011 b). The database provides a set of prices and taxes in the national currency per energy unit, and prices in national currency per toe. All prices are converted to €/toe, apart from the electricity price, which is expressed in €/MWh. All exchange rates used are from the IEA statistics (Energy Prices and Taxes), and all prices are given in 2009 prices.

LIBEMOD is well suited to analyse the responses of profit maximising electricity producers to the EU climate policy, which has a considerable impact on the production

[4] The Energy Prices and Taxes publication does not have any price information for Iceland. However, based on several sources it was possible to estimate a full set of prices for Iceland (www.statice.is, Lindhjem et al (2009) and www.bridgewest.eu) (Frischsenteret, 2014).

and investment for electricity, and might differ between electricity technologies, e.g. between coal-fired plants, gas-fired plants and renewables (Golombek et al., 2012).

5.1.3 Elasticities

First the direct price elasticity in the model will be described. The mathematical definition of direct price elasticities can be explained by the absolute change in the price p_i as dp_i, and the equivalent absolute change in the quantity demanded x_i of good i as dx_i, accordingly the direct price elasticity, can be written as;

$$\eta_{x_i p_i} = \frac{dx_i}{x_i} : \frac{dp_i}{p_i} = \frac{p_i}{x_i} * \frac{dx_i}{dp_i}$$

In general, the quantity demand for an item falls following an increase in the price of that item. In other words, in the usual case, the direct price elasticity is negative (Schneider, 1962). In LIBEMOD the mean values for coal (household and industry) are -0.21 in the short-run and -0.6 in the long-run, for fuel oil (household and industry) they are -0.14 in the short-run and -0.9 in the long-run, for industrial electricity the demand is -0.14 and -0.56, and the household demand is -0.23 and -0.43. However, biomass is represented by the same elasticities as for oil usage in every sector. In the case of elasticities for oil in the transport sector, this is country specific and ranges between -0.06 and -0.18 in the short run, and -0.18 and -0.49 in the long run. It is worth noting that these elasticities are also used for biofuels in the transport sector.[5]

The concept of cross price elasticity of demand can be expressed mathematically as:

$$\eta_{x_i p_k} = \frac{dx_i}{x_i} : \frac{dp_k}{p_k} = \frac{p_k}{x_i} * \frac{dx_i}{dp_k}$$

As previously indicated, x_i, represents the physical quantity demanded of an item No. i and p_k the price of the item K (Schneider, 1962). In LIBEMOD the cross-price elasticities are represented by equal elasticities across fuels and countries. Moreover, in the model cross-price elasticities are considered to be higher for industry than for households, which relies on the fact that firms are estimated to be more flexible in their choices than households are. That said, 0.0125 was chosen as the short-run elasticity for households and 0.05 as the long-run value. When modelling for industry, the values are set at 0.025 and 0.1. There is no distinction between service sectors and

---

[5] The direct price elasticities are based on Dahl (2006), *Survey of Econometric Energy Demand Elasticities – Progress Report,* which looked at 190 studies on elasticities that were published between 1991 and 2006. Based on these studies Dahl determined mean values for coal, oil and electricity (Frischsenteret, 2014).

household, thus the same elasticities were used for the service sector as for households (Frischsenteret, 2014).

The measure of income elasticity of demand in mathematical terms is:

$$\eta_{x_i y} = \frac{dx_i}{x_i} : \frac{dy}{y} = \frac{y}{x_i} * \frac{dx_i}{dy}$$

In other words, the elasticity of demand for the item No. i with respect to income is the linkage between the relative change in the quantity demanded and the relative change in income. This is represented by Y_i which is the income elasticity of demand for the item No. i as demonstrated in the equation above (Schneider, 1962).

The income elasticities in LIBEMOD are calibrated using average projected GDP growth rates from 2009 to 2035, average projected annual growth rates in energy consumption (for every sector and energy type) together with equivalent projected energy prices, and the price elasticities used in the model. The income elasticities can then be calibrated as the non-price changes in consumption with regard to the changes in GDP (Frischsenteret, 2014).

5.1.4 Electricity Production

Electricity production and consumption are endogenously determined by the price of electricity and other energy carriers (Golombek et al., 2012). In each specific country, electricity can be produced by various technologies, namely nuclear, fuel based technologies (where steam coal, lignite, oil, natural gas or biomass can be used as an input), fossil fuel based technology (either steam coal or natural gas), hydro (reservoir hydro, run-of-river hydro, and pumped storage hydro), and wind power and solar.

In LIBEMOD there is a distinction between plants with pre-existing capacities in the data year of the model (2009), and new plants that are constructed if such an investment is feasible. This difference lies in the fact that for old plants the capacity exogenously depreciates over time and it is not possible to increase it. In addition, for each type of fossil fuel based technology and for each model country, efficiency usually varies across existing plants. Furthermore, for new fossil fuel based technology, the efficiency is the same for an identical plant, but varies between technologies.

When considering investment, unit cost investment (US$/MWh) differs by technology. The return on investment is a higher installed capacity that allows for a higher production of electricity. In particular, at the margin the cost of investment is equal to the shadow value of the installed capacity (Aune, Dalen, & Hagem, 2012; Aune, Golombek, & Tissier, 2015; Frischsenteret, n.d.; Golombek, Greaker, & Kittelsen, 2013;Golombek et al., 2012).

The power producer obtains revenue from selling electricity and selling available maintained capacity to a national reserve capacity market, or a so-called system operator, who buys reserve power capacity in order to ensure that the countrywide electricity system does not fail. Power supply is associated with various cost factors, reflecting the costs of inputs, maintaining production capacity, and start-up, as well as the cost of investment.

In LIBEMOD all electricity producers maximise profits, taking into account how much of the installed capacity to maintain, how much to produce in each period, and how much to invest in production capacity contingent for various technology-specific constraints. This optimisation problem implies a number of first-order conditions, which determine the operating and investment decisions of the producer (Golombek et al., 2012). For instance, for reservoir hydro the reservoir filling at the end of a season should not exceed the reservoir limit. In addition, the overall use of water cannot outpace the entire availability of water (i.e. the sum of seasonal inflow of water and reservoir filling at the end of early season). Furthermore, the model offers an approach to model profitable investment in solar power and wind power based on certain criteria, as the number of solar and wind hours differ between sites, as well as access to sites being regulated. For the most part, wind power and solar power will mainly use a surface area that has an opportunity cost. It is therefore imperative to make an estimate of how much land may be available for this form of electricity generation in each and every country.

The factors that determine investment in solar power and wind power are based on a combination of different factors, e.g. political (to a certain degree that agents get access to production site), economic (i.e. the feasibility of investment, taking into account the accessibility of a production site), and technical factors which account for production site differences (Aune, Golombek, Moe, et al., 2015; Aune, Golombek, & Tissier, 2015; Golombek, Arne, et al., 2013)

5.1.5 Hydropower

It is clear that hydropower will play an important role in electricity export from Iceland to the UK, as hydropower can be used to serve peak load demands. It is therefore imperative to look more closely into how hydropower is represented in LIBEMOD.

The model separates hydropower into three types of hydroelectric generation: reservoir hydro, run-of-river, and pumped storage plants. Reservoir hydro, which has the ability to store water behind a dam, has two extra technology constraints. First, reservoir filling at the end of a season cannot exceed reservoir capacity, and second, total use of water, where total production of reservoir hydropower in a specific season plus reservoir filling at the end of the previous season should not exceed the total use of water, the sum of the reservoir filling at the end of previous season and the seasonal inflow capacity (TWh). For run-of-river hydropower technology there is a constraint on the use of water relative to the availability of water. That is, production in each time period cannot exceed the inflow of water. Pumped storage hydropower technology is defined as buying electricity in one period (e.g. during the night) and then utilising that energy to pump water up to a reservoir in order to produce electricity during a different (higher-price) period (e.g. during the day) by letting the water flow down through the generator.[6] The inflow capacity in an hydrological normal year is defined as the amount of precipitation that reaches the catchment area and is available for hydropower production (Aune, Golombek, & Tissier, 2015).[7]

5.1.6 International Transmission of Electricity

To demonstrate the fundamental economic concept of international transmission, the operating and investment decisions of an international electricity transmission company will be described; basic electrical trade theory warrants further exploration at this point.

There are always two possibilities when electricity is generated, that is whether to sell to a domestic consumer or to trade abroad, given that there is international transmission of electricity. To capture the elements behind such a decision, it is helpful to make a mathematical illustration. First, let q be a set of consumers of electricity, namely general consumers, industry, and intermediate consumers in the electricity sector (e.g., pump storage producer). The connection between the price for final electricity users of a consumer group q in time period t (P_{tq}^{x}), the price of electricity received by the producer in time period t (P_t), and the electricity retail variation parameter of consumer group q in time period t (α_{tq}), can be written as:

[6] The fixed operation and maintenance cost for a pumped storage and reservoir hydro is 20 €/kW/year, while it is 58.8 €/kW/year for run-of-river (Frischsenteret, 2014).

[7] For Iceland data from NORDEL (2008) was used (Frischsenteret, 2014).

$$P_{tq}^{x} = \left[\frac{1}{\theta_q}\left(P_t + \alpha_{tq}\right) + d_q\right] * \left(1 + \tau_q\right) \quad (1)$$ [8]

In which θ_q is the share of electricity which is not reduced during domestic transport and distribution, d_q is the total cost of domestic transportation, distribution and energy/environmental taxes, and τ_q is the VAT tax rate. Furthermore, how international transmission is designed after liberalisation should also be taken into account, as a subsea power cable will remove the isolation of the Icelandic electricity market and open up a new market for both Icelandic and UK suppliers. Thus, first the short run influence will be explained mathematically, and then the long run position.

Taking a short-run perspective, the limitation of international transmission from a country 'm' to a country 'n' can be expressed as K_{mn}^{0}. To begin with, consider that an agent possesses a transmission line between 'm' and 'n'. At every time period 't' the owner stands in front of two choices, that is to buy electricity in country 'm' and export to country 'n' (z_{mnt}) or to buy electricity in country 'n' and export it to country 'm' (z_{nmt}). The annual profit of an owner of the transmission between 'm' and 'n', after taking into consideration the share of the transported electricity, which is not reduced, defined as θ_{mn} and the operating costs of international transmission c_{mn} can be written as;

$$\pi_{mn} = \sum_{t}\left\{\left[P_{nt} - \frac{P_{mt}}{\theta_{MN}} - C_{MN}\right] z_{MNT} + \left[P_{MT} - \frac{p_{nt}}{\theta_{nm}} - c_{nm}\right] z_{nmt}\right\} \quad (2)$$ [9]

Additionally, an owner has to bear in mind that power is somewhat limited every time it flows along a transmission line, due to predetermined transmission line capacity. The orientation of the constraint can be described mathematically by the equation:

$$z_{mnt} - z_{nmt} \leq \varphi_t K_{mn}^{0} \perp \mu_{mnt} \geq 0 \quad (3)$$ [10]

Moreover, the assumption of a perfectly competitive equilibrium should be considered. By making such an assumption, the natural monopoly paradigm, i.e. the business of a transmission line owner is regulated. This will change the landscape of the electricity market, as a transmission line owner must act as a price taker in both countries (i.e. 'm' and 'n'). An owner will act correspondingly by maximising equation 2 subject to 3,

---

[8] LIBEMOD considers this, i.e. for such a relationship for electricity retail in each model country.

[9] Here $\frac{P_{mt}}{\theta_{mn}}$ is the loss-adjusted unit price in an exporting country where an owner can sell for P_{nt} in an importing country. Typically $\theta_{mn} = \theta_{nm}$ and $c_{mn} = c_{nm}$ (Golombek, Arne, et al., 2013).

[10] φ_t Can be defined as the number of hours in time period t. Trade occurs only in one direction in every period. In other words, in each period, it is z_{mnt} or z_{nmt} that is zero or both at the same time (Golombek, Arne, et al., 2013).

with respect to the quantity traded in each direction and at any given time period. The first-order condition for this problem, i.e. for export from country 'm', is then given by the following expression:

$$P_{nt} - \frac{P_{mt}}{\theta_{MN}} - C_{mn} - \mu_{mnt} + \mu_{nmt} \leq 0 \perp z^{E}_{mnt} \quad (4)$$

It follows from the first order condition of the agents that if it is optimal to export from country 'm' in period t, then $\mu_{nmt} = 0$. In addition, the loss-adjusted price difference within the importing and exporting country $\left(P_{nt} - \frac{P_{mt}}{\theta_{mn}}\right)$ should be equal to the entire marginal costs. In other words, it should be equal to the monetary cost of transporting electricity (c_{mn}) plus the shadow value of increased capacity (μ_{mnt}).

In fact, since the trade has been defined as a market arbitrage, i.e. the agent buys electricity in one market and then sells it on to another market, it is possible to make an alternative interpretation: a publicly owned transmission company is advised to set tariffs in order to compensate for marginal costs, expressed as c_{mn} apace with the capacity expense $\mu_{mnt.}$.

For this setup the capacity charge can only be positive, given that the capacity is entirely exploited, and in addition should be set to an acceptable degree to guarantee that demand for transportation cannot be greater than capacity. According to this setup, there is a perfect third-party access (TPA), whereby any agent can participate in trading to undertake the market arbitrage (i.e. $P_{nt} - \frac{P_{mt}}{\theta_{mn}}$) while opposing a tariff corresponding to the monetary cost of transporting electricity plus the shadow value of increased capacity ($c_{mn} + \mu_{mnt.}$). When there is a market balance, the aforementioned agents earn zero profit (in particular, pure profit).

However, in the long run the owner of a transmission line between countries 'm' and 'n' is able to increase transmission capacity. To consider this possibility in a mathematical representation, the annualised (unit) capital cost for the expansion of the international electricity transmission line can be expressed as c^{inv}_{mn} together with K^{inv}_{mn} as the notation for the increase in transmission capacity. This will affect the earlier equation for profit. In other words, the profit is given by equation (2) less $c^{inv}_{mn} K^{inv}_{mn}$, and what is more, the K^{0}_{mn} in equation (3) will be replaced with K^{0}_{mn} + $K^{inv}_{mn.}$ This will imply that in the long run, the first-order condition for investment in electricity transmission can be written as:

$$\sum_t \varphi_t \left(\mu_{mnt}^E + \mu_{nmt}^E\right) \leq c_{mn}^{inv} \perp K_{mn}^{inv} \geq 0 \quad (5)$$ [11]

It should be indicated however, that once electricity is liberalised, domestic imbalance is transposed to the international market. In other words, a country facing severe supply problems will increase its import from other model countries. Thus, a subsea power cable from Iceland to the UK could be viewed as supply security, as it allows energy to flow to Iceland at times of low hydro generation potential, e.g. due to unusually low precipitation levels (Golombek, Arne, et al., 2013).

5.2 Main Scenarios

In LIBEMOD the base year 2009 is generally used to calibrate a number of demand parameters that are used as a benchmark to model the long-run equilibrium in 2030 scenarios. In the next three scenarios, it is assumed that the EU's climate policy goal for 2030 has been achieved. The EU climate policy for 2030 relies on a decision that was implemented in the autumn of 2014, that by 2030 GHG emissions should be 40% lower than in 1990. However, the policy is applied to different sectors, i.e. the emissions trading system (ETS) sector (electricity generation and large carbon-intensive manufacturing firms) and the remaining sectors (non-ETS). The ETS sector has to reduce GHG emissions by 43% relative to 2005, whereas the non-ETS sector has to reduce its emission by 30%. Furthermore, the renewable share in final energy consumption should be at least 27%. All targets are at the EU level and therefore are not implemented as national targets.

In LIBEMOD there is one EU-target for emissions within the ETS sector, which uses a common quota system and one common EU-30 target for emissions in the non-ETS sector which is enforced by a common uniform tax (Aune, Golombek, & Tissier, 2015).

Figure 10 shows the carbon dioxide price in EU-30 countries in 2030. In order to reach the climate targets, the ETS price is 12 €/tCO2, while the non-ETS price is 242 €/tCO2. The difference between prices for the ETS and non–ETS sectors reflects the greater flexibility among producers in the power sector than for end users (Aune, Golombek, & Tissier, 2015).

[11] The equation indicates that investment increases capacity in both directions, and that the increased capacity can be exploited in all periods (Golombek, Arne, et al., 2013).

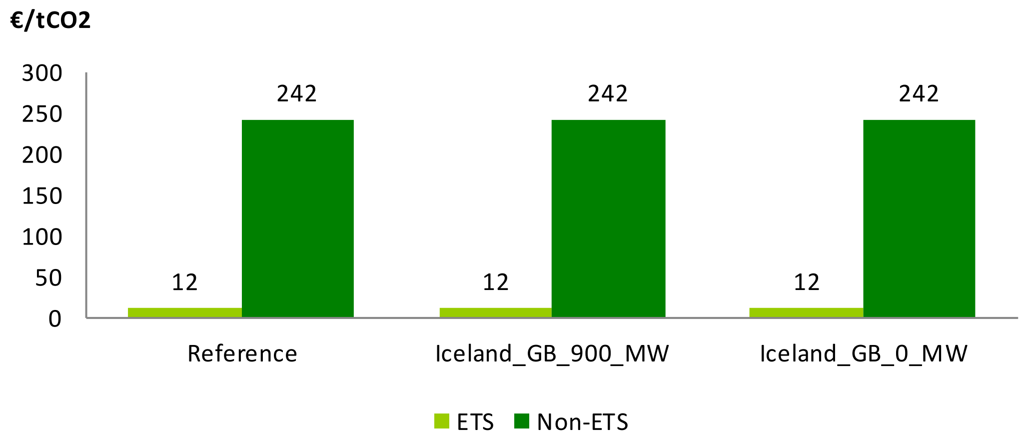

Figure 10: Carbon dioxide prices in 2030 (€/tCO2), EU-30

In the first scenario there is no cable but the 900 MW projected cable is present in the second scenario (see Section 2.4.1), and finally the reference scenario, where all profitable transmission investments are realised. In the reference scenario there is actually more than 900 MW capacity from Iceland to the UK, which means that according to the model, it is optimal to invest in more than 900 MW capacity, more specifically, 1471 MW. However, it should be noted that it is highly likely that some bottlenecks may remain in this case, as it is costly to increase capacity. Hence, the realised capacity in this scenario will be fully utilised in at least one of the periods.

Table 1: Alternative scenarios for 2030

Scenario 1	Transmission capacity from Iceland to the UK is fixed at zero, i.e. no cable.
Scenario 2	Scenario with the projected cable of 900 MW between the UK and Iceland.
Scenario 3	Reference scenario, where all profitable transmission investments are achieved via a 1471 MW cable

5.3 Numerical Results

5.3.1 Iceland

5.3.1.1 Net Export of Electricity and Electricity Prices

It is useful to evaluate briefly the economic theory behind the international transmission of electricity, before analysing the effects of the subsea power cable between Iceland and the UK.

When liberalising international trade between Iceland and the UK, electricity is transferred from a low-price country to a high-price country in order to obtain arbitrage profits. However, due to the costs of international transmission, as well as capacity constraints in international transmission, producer prices are not completely equalised across countries (e.g. in LIBEMOD the domestic transportation and distribution costs for household is 156.40 €/toe and 46.35 €/toe for industry in Iceland).

In the long run when transmission capacity can be expanded, price differences between countries are lower. Because liberalisation of international transmission lowers the coefficient of variation for national producer prices, it could be presumed that the coefficient of variation for national producer would also drop. Consequently, as a result of liberalisation the difference in the producer prices between countries decreases. Practically, countries with initially high producer prices experience lower producer prices, and similarly, the end-user prices in these countries, which initially are low also tend to decrease. Countries which originally have low producer prices experience higher producer prices, and end-user prices in these originally high countries, also tend to rise. It follows that low initial end-user prices are increased, whereas the high initial end-user prices are decreased (Golombek, Arne, et al., 2013).

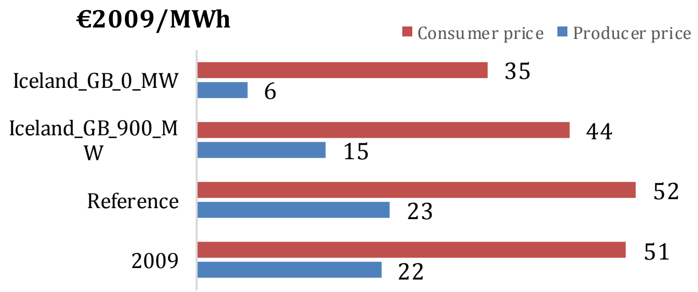

Figure 11: Electricity price in Iceland for consumers and producers in 2009 and 2030

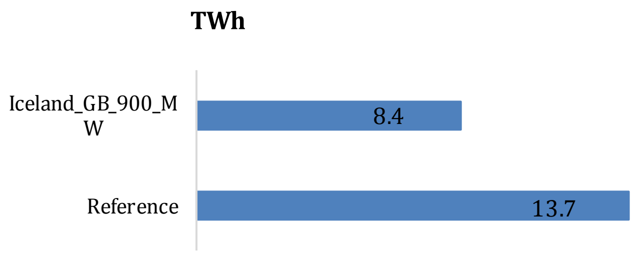

Figure 12: Net export of electricity from Iceland to UK in 2030

Figure 11 and Figure 12 show the prices of electricity in Iceland and the net export of electricity from Iceland to the UK. These are weighted average prices over all sectors (including the electricity sector). This is a clear difference between prices for consumers and producers within the scenarios for 2030. By looking at the difference between the prices when there is fixed transmission capacity from Iceland to the UK at 900 MW, and when the capacity is fixed at zero at the same time, it can be seen that the prices vary considerably. Under the circumstances of a 900 MW subsea power cable compared to no subsea power cable, the producer prices are 150% higher and the consumer prices are 26% higher.

An interesting observation in Figure 11 is the difference in prices between the scenarios when the capacity is 1471 MW and the capacity is fixed at 900 MW, where the producer prices are 53% higher and the consumer prices 18% higher in the 1471 MW cable scenario. The main reason for this is that the cable leads to export, resulting in higher prices in Iceland, and this accelerates further hydro production.

Figure 12 shows how the net exports of electricity (TWh) from Iceland to the UK changes between 900 MW and 1471 MW scenario. This makes sense, since the transmission capacity is increased in the 1471 MW scenario, hence the net export of electricity increases by 63%, from 8.4 TWh to 13.7 TWh.

5.3.1.2 Electricity Production

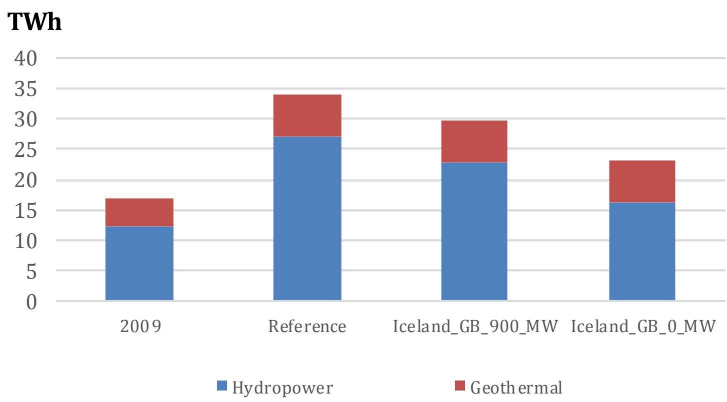

Figure 13: Sources of electricity production in Iceland for the different scenarios

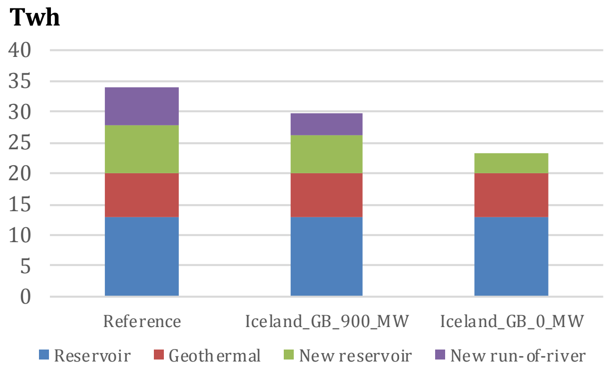

Figure 14: Electricity production sources in Iceland for the different scenarios

Figure 13 and Figure 14 show the equilibrium composition of electricity technology in 2009 and the alternative scenarios in 2030. Geothermal electricity production is exogenous in the model, i.e. unchanged across scenarios at 7.013 TWh. According to the Icelandic National Renewable Energy Action Plan, electricity generation from geothermal sources is estimated to increase by 12% from 5.2 TWh in the year 2014 to 5.8 TWh in year 2020 (Ketilsson et al., 2015). By that token, 7 TWh in 2030 is realistic if the same growth is expected.

The difference lies in variations in hydroelectric production within the scenarios.[12] First, the change in electricity production in the 900 MW projected cable scenario will be compared relative to the no cable scenario. Figure 14 shows that electricity production from new run-of-river increases by 3.57 TWh compared to the no cable scenario. In addition, electricity production from new reservoir production increases by 3.14 TWh more in the 900 MW scenario compared to the no cable scenario.

Comparing the scenario of a 1471 MW cable to a 900 MW cable, electricity production from new run-of-river increases by 6 TWh compared to 3.57 TWh when the transmission capacity is fixed at 900 MW.[13] The increase from new reservoir production is 1.695 TWh is also compared to the 900 MW scenario. As mentioned

---

[12] The fixed operation and maintenance costs for geothermal is 101,8 €/kW/year, based on data from the technology briefs issued by IEA ETSAP (Frischsenteret, 2014) .

[13] To estimate hydropower potential in Iceland data from the World Atlas and Industry Guide was used. The economic potential is defined as the portion of the gross theoretical potential that could be or has already been developed under local economic conditions with current technology. It is estimated that the economically feasible hydro potential is 40 TWh. Furthermore, it is not clear whether the economic potential includes sites that would be unacceptable to develop due to social or environmental restrictions (Frischsenteret, 2014).

previously, because of higher prices, the run-of-river production increases most in the 1471 MW scenario and least in the no-cable scenario.

5.3.1.3 Economic Welfare Changes

Table 2: Change in welfare in energy sector in Iceland relative to no cable scenario, million, €$_{2009}$ per year

	1471 MW Cable	900 MW Cable
Consumer surplus (household, services, industry)	-373	-212
Producer's surplus electricity	488	244
Trader surplus	0	32
Total	**115**	**64**

The economic welfare changes for the alternative scenarios in 2030 are now considered, starting with the 900 MW cable scenario compared to the no cable scenario. Table 2 shows that when there is a projected cable of 900 MW, the economic welfare in the energy sector increases by €64 million per year. All Icelandic energy consumers (i.e. household, services and industry) lose €212 million per year (higher electricity prices) while Icelandic electricity producers gain €244 million per year. This is mainly because Icelandic electricity producers can sell electricity to the competitive international market.

The big loss in consumer surplus is to some extent due to higher prices for the industry sector, together with considerably higher electricity prices for all sectors. In addition, there is an increase in trader surplus of €32 million per year, which benefits the owner of the electricity transmission line between Iceland and the UK. Trader surplus rises when electricity transmission capacities are used up and there a price difference remains which overcomes the operating costs of transporting electricity.[14]

In the case of a 1471 MW cable compared to no cable, the economic welfare in the Icelandic energy sector increases by €115 million per year according to the results. Table 2 shows that producers benefit from building such a subsea power cable while there is a consumer loss. In total, Icelandic electricity consumers lose €373 million per year, whereas the country's electricity producers gain €488 million per year. Moreover, Icelandic electricity export increases, and this increase in exports is marked as

[14] The general assumption in LIBEMOD is that trader surplus is split into two, so that the exporter and importer share the trader surplus equally (Aune, Golombek, & Tissier, 2015).

producer's surplus electricity in Table 2. Furthermore, the trade surplus is zero, since the price differentiation does not exceed the total costs of transporting electricity. In other words, all profitable transmission investments are fulfilled (Aune, Golombek, Moe, et al., 2015).

5.3.2 United Kingdom

5.3.2.1 Net Export of Electricity and Electricity Prices

From Figure 15, it can be seen that the net import of electricity to the UK by 2030 will be 29.2 TWh if 900 MW capacity is transmitted from Iceland to the UK, as opposed to 21.7 TWh if there is no subsea power cable. From this it can be assumed that Iceland contributes to reducing the cost of enabling the integration of UK intermittent renewables, given its reduced cost of low carbon energy, compared to domestic marginal alternatives.

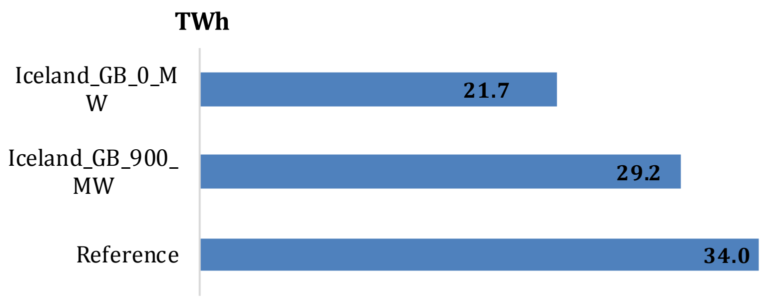

Figure 15: Net import of electricity to UK in 2030

Consequently, with an international electricity transmission line the UK will export electricity to Iceland at times of excess wind power generation. In addition, the net import of electricity to the UK will increase to 34 TWh when there is fixed transmission capacity from Iceland to the UK at 1471 MW compared to 29.2 TWh if there is a 900 MW capacity.

5.3.2.2 Electricity Production

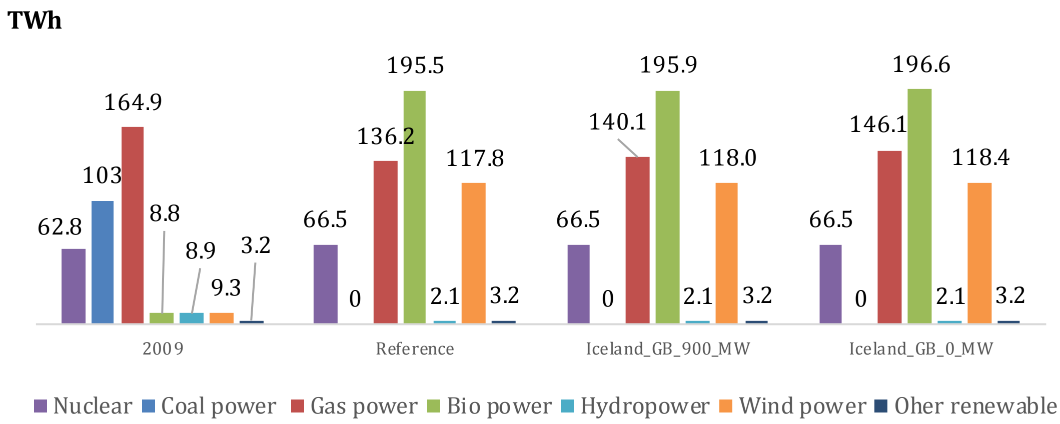

Figure 16: Electricity production sources in the UK in 2009 and 2030

Figure 16 shows electricity production in the UK in 2009 and 2030. It demonstrates that the total production of electricity is roughly at the same level in the 1471 MW cable scenario, under a 900 MW subsea power cable and with no subsea power cable. However, the composition of technologies are not static, as they change radically from the base year 2009 compared to the other scenarios in 2030.

In the no cable scenario compared to the base year in 2009, coal power is completely phased out, as investment in new coal power capacity is no longer profitable due to the energy and climate policy. Higher carbon dioxide prices, which Figure 10 shows, are clearly the most harmful for coal power due to higher emission coefficients. In addition, gas power production drops from 164.9 TWh in 2009 to 146.1 TWh in the no cable scenario. Figure 16 also reveals that investment in renewable power production is increased significantly, compared to the base case situation (Golombek et al., 2012). The market shares of bio power for total production increases from 2% in 2009 to 37% in the no cable scenario, and wind power increases from 3% in 2009 to 22% in 2030.

Next to be considered is the 900 MW cable scenario compared to the no cable scenario. Electricity production from gas power is 140.1 TWh in the 900 MW cable scenario, compared to 146.1 TWh if there is no cable, while bio power electricity production is 195.9 TWh compared to 196.6 TWh, and wind power electricity production is 118 TWh compared to 118.4 TWh.

If there is a subsea power cable of 1471 MW then electricity production from gas power is 136.2 TWh compared to 140.1 TWh if there is a 900 MW cable, while electricity production from bio power is 195.5 TWh compared to 195.9 TWh, and electricity production from wind power is 117.8 TWh compared to 118.04 TWh. However, electricity production from hydropower is roughly the same across all scenarios. In addition, lower prices are the reason for the changes in electricity production between the 900 MW scenario to 1471 MW scenarios, due to more imported electricity.

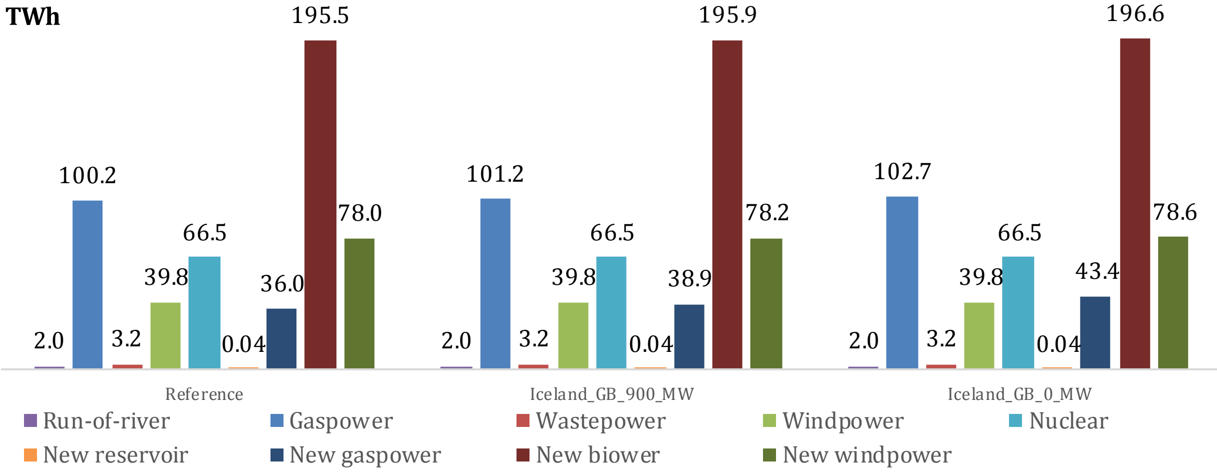

Figure 17: Electricity production in UK by source in 2030

Figure 17 illustrates this difference even more clearly. Even though there is a decrease in gas power production (TWh) from the base year 2009 compared to the other scenarios in 2030, there is still investment in new gas power. The reason for this is that new plants are more effective than existing plants, and hence emit less carbon dioxide per unit KWh produced (Golombek et al., 2012).

A subsea power cable between Iceland and the UK will offer a means to decrease imported fossil fuels in the UK. Comparing the net import between alternative scenarios in 2030 reveals that there is an increase in gas imports in the no cable scenario compared to the 900 MW cable scenario; 61.3 Mtoe/year versus 60.4 Mtoe/year. In addition, for a 1471 MW cable gas imports are 59.8 Mtoe/year compared to 60.4 Mtoe/year in the 900 MW cable scenario. Thus, a subsea power cable will increasingly diversify renewable energy power supply and offer a means to decreasing UK dependency on imported fossil fuel.

5.3.2.3 Economic Welfare Changes

Table 3: Change in welfare in the energy sector in the UK relative to the no cable scenario, million €$_{2009}$ per year

	1471 MW Cable	900 MW Cable
Consumer surplus (household, services, industry)	139	86
Producer's surplus electricity	-126	-77
Trader surplus	0	32
Sum	**13**	**41**

In this section the economic welfare between scenarios will be compared to the no cable scenario. The effects of building a subsea 900 MW power cable are shown in Table 3, which indicates that there is an increase in the energy sector welfare in the UK of €41 million per year. UK energy consumers in total gain €86 million per year, whereas UK electricity producers lose €77 million per year. Furthermore, there is an increased trade surplus of €32 million per year, which benefits the owners of the electricity transmission line between Iceland and the UK. As previously mentioned, a trade surplus arises when electricity transmission capacities are exhausted and there is a price difference which exceeds the operating cost of transporting electricity. In general, the exporter and importer share the trader surplus equally in LIBEMOD (Aune, Golombek, Moe, et al., 2015).

For a 1471 MW cable the economic welfare in the UK energy sector increases by €13 million per year according to the results. All end users of energy in the UK gain €139 million per year, while UK electricity producers lose €126 million per year. Furthermore, the trade surplus is zero, since there is no price differentiation that exceeds the total cost of transporting the relevant electricity.

The changes in welfare in both scenarios relative to the no cable scenario are opposite to those in the Icelandic case. That is, the gain in consumer surplus in the energy sector and the loss among producers in the electricity sector is due to lower prices; however, the total welfare in the energy sector is expected to increase.

5.3.3 EU-30 Countries

5.3.3.1 Energy consumption

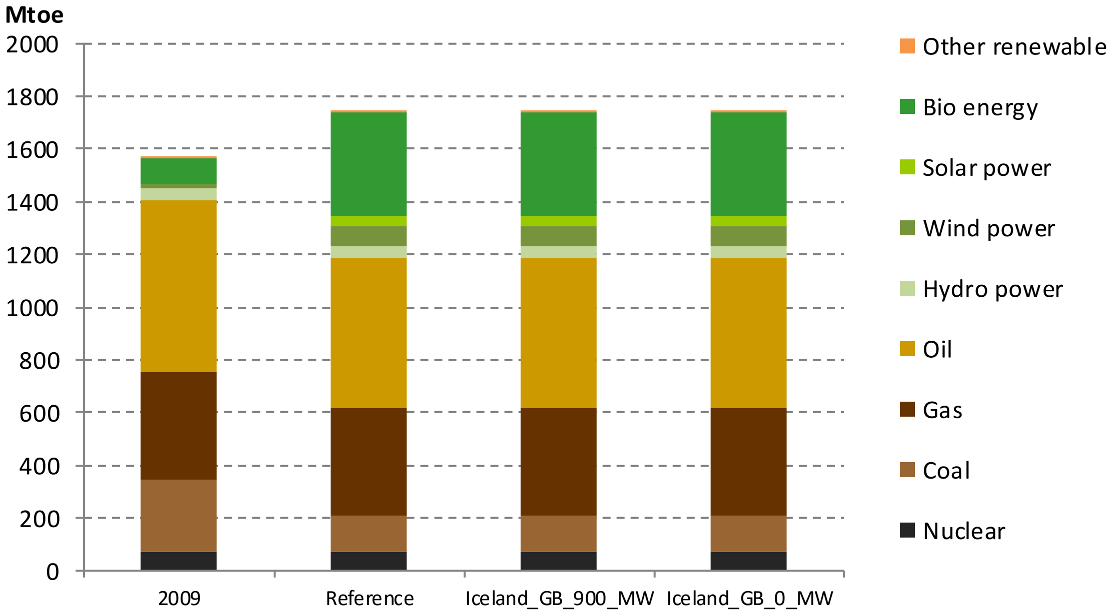

Figure 18: Energy consumption in EU-30 countries in Mtoe

Figure 18 shows how total consumption of energy in EU-30 countries varies across scenarios. The figure combines the consumption of primary energy and the consumption of electricity.[15] This figure demonstrates how increasing the climate policy effort brings with it substantial increases in renewable energy consumption in 2030 compared to 2009. It is projected that the consumption of wind power, solar power and bio energy would increase significantly by 2030. What is more, consumption of coal drops by 50% in every scenario compared to 2009, while oil is predicted to drop by 13% and consumption of natural gas by about the same.

It can be seen that consumption of energy is around the same level within the three scenarios in 2030. However, it is difficult to assess the increase in hydropower consumption in the 1471 MW cable scenario, compared no subsea power cable between Iceland and the UK. Nevertheless, consumption is expected to increase by

[15] It is not straightforward how to compare these values. In the figure, consumption of electricity has been transformed from nuclear, hydro, solar and wind power to consumption of primary energy using a standard transformation rate of 11.63 MWh/toe (Aune, Golombek, & Tissier, 2015).

2%. The reason why consumption is mainly at the same level in all the alternative scenarios is that the Icelandic market is so small compared to the EU market.

5.3.3.2 Electricity production and capacity by technology, EU-30

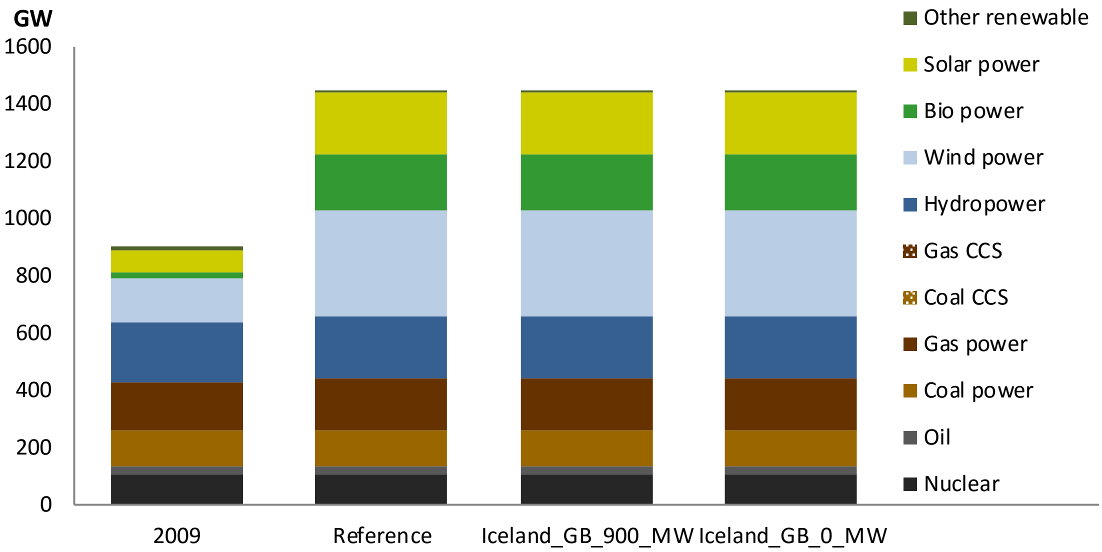

Figure 19: Capacities by technology in EU-30 countries

Figure 19 shows how the installed capacity of electricity technologies in EU-30 alters across scenarios. Noticeable differences can be observed between total installed capacities in 2009 compared to the other scenarios in 2030, from 950 GW to 1451 GW. A plausible explanation for this is that the increase for the most part is a consequence of economic growth between 2009 and 2030 (Aune, Golombek, & Tissier, 2015). Capacity by technology in EU-30 countries is more or less the same within the scenarios in 2030, aside from differences in hydropower-installed capacities. It is estimated in the 1471 MW cable scenario hydropower capacity is 217 GW, compared to 214 GW for no cable. Furthermore, bio power capacity is predicted to be 194 GW when there is no cable and 193 GW for the other two scenarios in 2030.

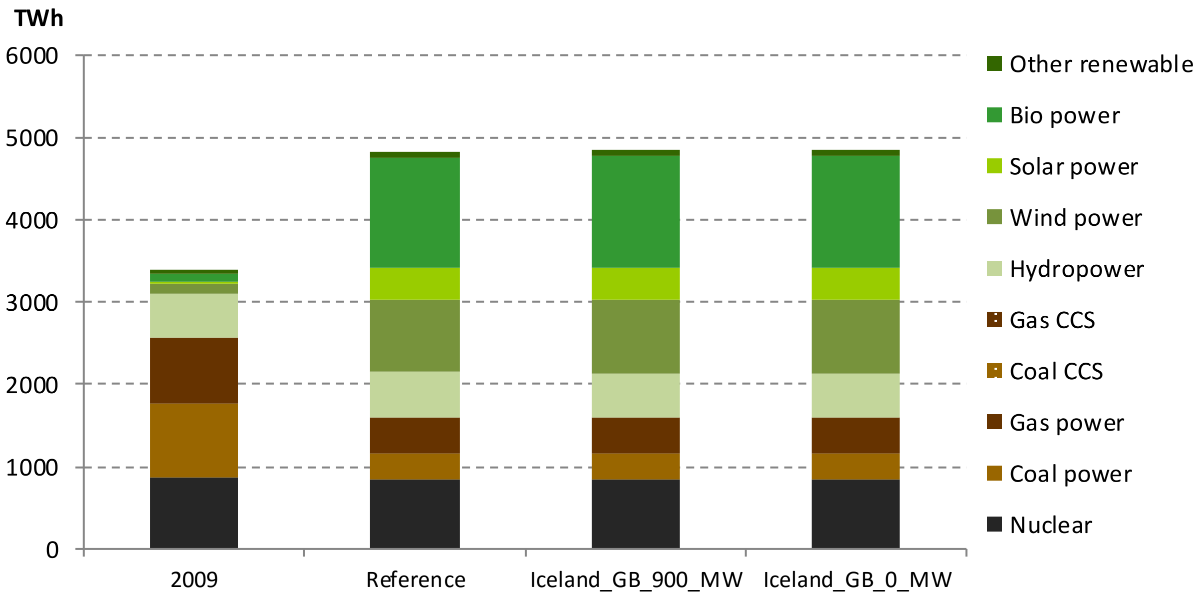

Figure 20: Electricity production in EU-30 countries

Electricity production is shown in Figure 20, and this highlights how changes in capacity are converted into changes in electricity production. Before analysing the difference between scenarios, one should bear in mind that production of electricity cannot be stored, and there is a fixed net import of electricity to EU-30 countries. Thus, the change in production of electricity is equal to the change in electricity consumption.[16]

Figure 20 shows that there is a significant increase in electricity production from renewable sources in all scenarios in 2030, compared to 2009. However, electricity production from coal and natural gas declines substantially and there is also a small decline in nuclear electricity generation. The main reasons for the increase in renewable electricity production are wind power, solar power and bio power. The total production of electricity is more or less at the same level in the various scenarios in 2030, except that there is a small change in the composition of electricity production. For instance, hydropower production is estimated to be 542.2 TWh for the 1471 MW cable, 538.3 TWh for the 900 MW cable, and 531.6 TWh if there is no international transmission of electricity between Iceland and the UK.

[16] Before losses in transport and distribution (Aune, Golombek, & Tissier, 2015).

5.4 Concluding Remarks

This part of the thesis has examined the impact of building a subsea power cable between Iceland and the UK. The results of a large-scale simulation model for the European energy market (LIBEMOD) following the implementation of a cable have been described and presented.

Alternative scenarios in 2030 have been examined regarding how the equilibrium changes if one of the main assumptions of the scenario is changed, i.e. no cable, a 900 MW cable and a 1471 MW able. Interestingly, a 900 MW subsea power cable between Iceland and the UK was found to increase production of electricity significantly in Iceland due to higher prices. This leads to a significant redistribution from consumers to producers and an increase in the welfare of the energy sector in Iceland by €64 million per year, compared to the scenario of no cable.

In addition, a connection to cheap green power supplies may be beneficial to the UK, as the economic welfare in the UK increased by €41 million per year for a 900 MW cable and by €13 million per year for a 1471 MW cable, compared to the scenario of no cable. The economic effects of a 900 MW cable in the electricity sector will result in the consumer surplus increasing by €86 million per year while producer's surplus will decline by €77 million per year, compared to the scenario of no cable.[17]

When looking at both scenarios, i.e. a 900 MW and 1471 MW cable, an increase in total economic welfare for both countries is observed when there is investment in greater capacity, i.e. the change from a 900 MW to 1471 MW cable. In addition, the total producer and consumer surplus increases for both countries in the 1471 MW scenario, compared to the 900 MW scenario.

[17] It should be stated that these economic effects in the electricity sector will cause general equilibrium effects along the remaining economy. Part of these effects may enhance the initial welfare. In contrast, the welfare evaluation is restricted to a sector that is included in the LIBEMOD model, that is action that is related to consumption and production of energy, transport of energy, and distribution of energy. LIBEMOD is not a Computable General Equilibrium (CGE) model; in other words, it does not deal with the entire economy (Aune, Golombek, Moe, et al., 2015).

Chapter 6 - Optimising Renewable Energy

Generally, the notion of renewable energy has been considerably discussed and studied in the academic literature. The driving force behind most of the research is that an energy system based on the usage of fossil fuel, as it is today, is not environmentally sustainable, especially if global temperature rises this century are to be kept well below 2 degrees, although still above pre-industrial levels. Hence, world governments have developed, or are developing, various measures to increase the share of renewable energy within the energy mix (Huuki, 2014; United Nations, 2015). Despite the clear benefits of renewable energy, it brings certain difficulties into play, given that almost all renewable energy technologies are subject to prevailing natural forces. Thus, their use rests mostly on advanced design and preparation, as well as control optimisation methods (Manzano-agugliaro et al., 2011).

Electricity energy storage offers a promising way to develop the growing variation in the electricity grid, due to short time-scale volatility of renewable energy resources. Hydro-storage is generally considered the uppermost storage technology, as a hydroelectric power station has the potential to store the natural flow of water, release the water, and produce electricity when demand is high. This causes a buffering effect for the natural variations in supply of electricity from renewable power sources such as wind, solar or run-of-river. What is more, one of the interesting aspects of energy storage is that it introduces an arbitrage possibility. Arbitrage provides a mechanism to ensure that prices do not deviate substantially from their fair value over long periods, thereby increasing the efficiency of the deregulated electricity energy market.

It is essential to estimate the arbitrage value of storage, which is a result of arbitrage opportunities in power markets, and is an important factor in power system planning. (Investopedia Staff, n.d.; Löhndorf, Minner, & Wozabal, 2013; Qin, Sevlian, Varodayan, & Rajagopal, 2012). In this context, the natural phenomena of renewable energy flow in Iceland will be briefly reviewed and then a strategy which involves buying and selling electricity decisions through a subsea power cable between Iceland and the UK introduced to explore the arbitrage possibility.

6.1 Hydropower

Hydropower is electricity generated using the energy from flowing water, i.e. it depends on water driving turbines. The force of the falling water provides the primary energy to turn a turbine that drives a generator. Hydroelectricity can be generated using uncontrolled river flows, or dams that both raise the water level of a river to create falling water and control the flow of water. In the latter case, a reservoir can store water over several years (Førsund, 2007; Wisconsin Valley Improvement Company, 2016).

Hydropower is a well-tried and sophisticated technology. The fundamental concept of harnessing the power of moving water to generate electricity by running the water to turn turbines and generators that produce electricity, has been used since the beginning of the 20th century, and in the 1920s, 40% of electricity produced in the US came from hydropower (Huuki, 2014). Since there is no direct cost in hydropower production, i.e. maintenance is generally a function of the size of the capital structure and not the present output level, a zero current cost that varies with output can be realistically assumed. Hence, water values are the only variable cost, which implies an opportunity involved in water allocation. In a sense, the cost today is the benefit obtained by using water tomorrow (Førsund, 2007). In other words, water allocation largely depends on electricity price expectations.

Figure 21 shows the benefits for an increase of water delivery from x_1 to x_2. When a hydro reserve can be stored then there is an opportunity to transfer water, in order to use water for production when prices are high (Huuki, 2014).

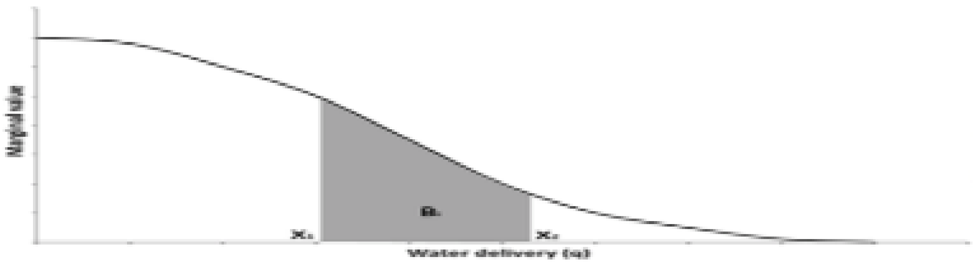

Figure 21: Benefits from an increase of water delivery from x_1 to x_2
(Tilmant, A; Macian-Sorribes, H, 2015)

The competitive outcome for hydropower is not where price equals marginal costs, but where price equals the water value. The water value measures the change in utility due to a marginal increase in the amount of water available, and is basically the alternative-use-cost of water (Førsund, 2007). If the strategies for pricing reflect the water value, then they will act as an economic instrument for efficient water resources management, adjusting the interaction of demand and supply by focusing on the demand side and allocating water where it is most highly valued. However, public water allocation has a tendency to provide large-scale infrastructure that can be out of the range of the private investment capacity. Thus, it typically fails to yield optimal economic performance and offers no incentive for water-efficient management (Tilmant, A; Macian-Sorribes, H, 2015).

Most of the research about solving hydropower storage scheduling problems falls into two categories: those that follow a system economic approach (e.g. can be used to solve a linear program in a system context and integrate cost-efficient storage capacity) and those that concentrate on the operation of a singular plant or portfolio of hydro storage. The latter includes seasonal hydropower storage, which concentrates on improving the optimisation methods (Braun, 2016).

6.2 Geothermal Energy

Geothermal energy is the heat contained inside the Earth. Geothermal heat pumps, which tap into heat close to the Earth's surface to heat water or provide heat for buildings, are a highly efficient renewable energy technology. Geothermal electricity production follows the same principle as for any other traditional steam based production, such as fossil-fuel plants and nuclear power plants. However, geothermal power plants use steam to drive electric generators, and the steam is produced from reservoirs of hot water found a few miles (or more) beneath the Earth's surface (Heimisson, 2014; RenewableEnergyWorld.com, n.d.; The United States Environmental Protection Agency, 2016; Union of Concerned Scientists, 2014).

This technology relies on the fact that at depth the Earth has a reasonably constant temperature. The key benefit of using geothermal energy is that this renewable energy source can deliver power 24h a day, i.e. it is constant, as well as independent of natural variations, making it dependable in the short and medium term (Hreinsson, 2007; Manzano-Agugliaro et al., 2011). Figure 22 shows a purely thermal system using geothermal energy.

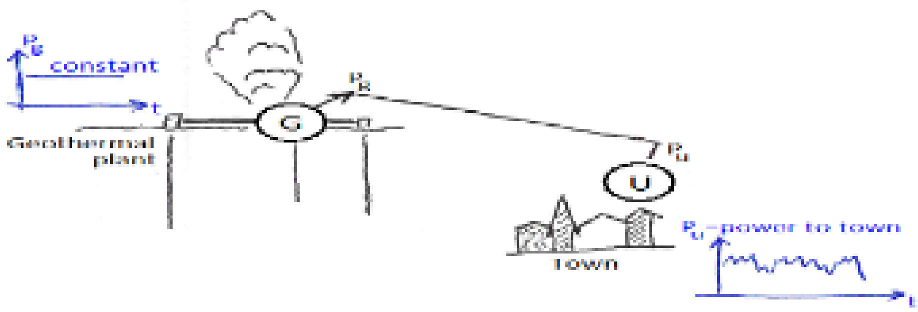

Figure 22: A purely thermal system
(Pétursson, 2012)

It is expensive to construct a geothermal power station, although operating costs are low. Geothermal based heat and power plants have been described as more cost-effective than hydro plants, due to their ability to meet both electricity generation and space heating demands (Hreinsson, 2007; Manzano-Agugliaro et al., 2011). Geothermal power plants account for a large share of the market in Iceland, for both electric power generation and space heating (Hreinsson, 2007). Furthermore, most of the production of geothermal electricity in Iceland is for energy-intensive industry (Kristjánsdóttir, 2014).

Geothermal energy, with its recognised technology and sufficient resources, could have a substantial impact on the road to protecting the climate by reducing the emission of GHGs. In that context, it is worth mentioning that as stated by the US Environmental Protecting Agency, geothermal power plants emit around five percent of the carbon dioxide, one percent of the sulphur dioxide, and less than one percent of the nitrous oxide that is emitted by a coal-fired plant of the equivalent size. However, only a small fraction of the geothermal potential has been developed, and there is an opportunity for stimulating usage of geothermal energy both for electricity generation and for direct exploitation (Geographical Magazine, 2014; Manzano-agugliaro et al., 2011)

6.3 Hydro-Thermal Systems

Electricity generated by hydropower and geothermal power has turned out to be economically feasible, given the adaptability of water reservoirs and the constant output of geothermal plants (Hreinsson, 2007). Additionally, when looking at the benefits for the UK, an interconnector reduces the cost of low carbon energy compared to domestic marginal alternatives. For instance, new wind parks and their flexibility contribute to reducing the cost of enabling the integration of UK intermittent renewables (Landsvirkjun, 2016c).

Figure 23 shows that the levelised cost[18] of electricity among mature technologies, and shows that geothermal and hydropower has been mostly stable since 2010. Moreover, biomass for power, geothermal and hydropower have contributed to low-cost electricity for many years, including where untapped economic resources can be obtained (IRENA, 2015).

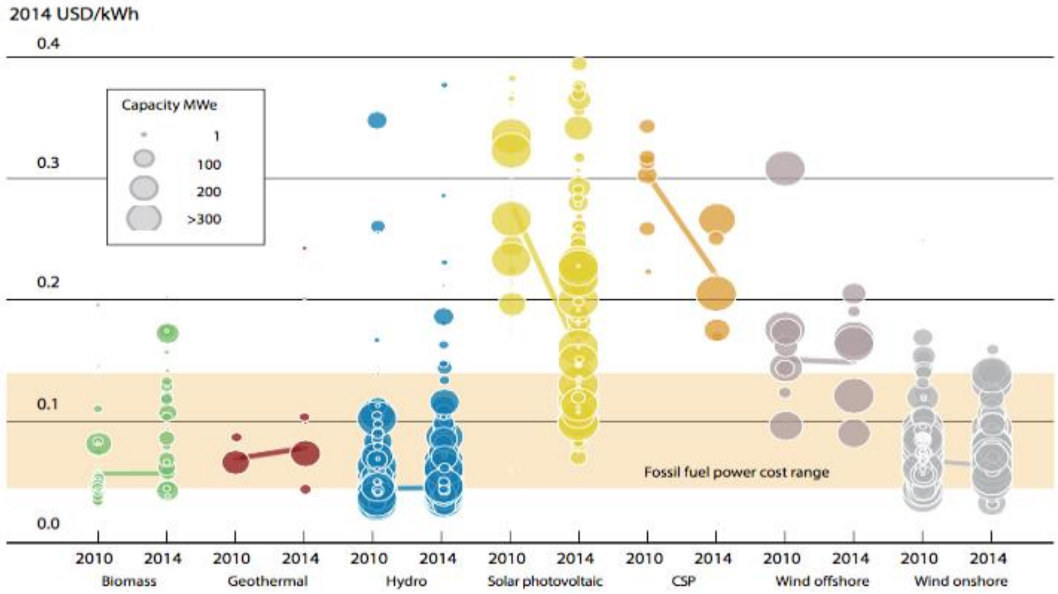

Figure 23: The levelised cost of electricity from utility-scale renewable technologies, 2010 and 2014
(IRENA, 2015)

It is worth noting, however, that geothermal, in comparison to hydropower plants, produces greater atmospheric pollution but has less need for land usage, especially if reservoirs are considered. In addition, they have higher availability, given that hydropower plants are vulnerable to weather conditions (Heimisson, 2014). In contrast, hydropower provides a more balanced energy supply into the energy system. Electric energy is difficult to store after production, hence the advantage of hydropower production is that production can be conditionally supervised on demand (Kristjánsdóttir, 2014). Storage enhances efficient water resources management, due

[18] The term 'levelised' applies to the average costs discounted over the project life cycle, usually 20 to 30 years, including all costs (The World Bank, 2012).

to the ability to transfer water between periods when economically viable (Steeger, Barroso, Member, & Rebennack, 2014).

In terms of the net export of electricity through an interconnector, hydropower plants with large reservoirs can serve as energy storage when electricity demand in the UK is low, and at peak load times (i.e. when electricity prices are highest) hydropower plants in Iceland can operate at full capacity. Furthermore, it provides an export opportunity for the surplus energy in the renewable hydro system, which has not been utilised due to economical and operational limitations (Askja Energy Partners, 2014a; Landsvirkjun, 2016c).

This adaptability makes bidding tactics appropriate for hydropower producers. It should however be indicated that bidding and production has to match and cannot be considered on a case-by-case basis. That said, when considering the bidding problem, both pool exchange and production conditions should be considered. For that reason the decision process for the bidding problem is a separate phase. Indeed, bidding decisions are made using information on market prices that are based on likelihood, when in fact it is possible to manage productions based on fresh information and knowledge (Fleten & Kristoffersen, 2007).

Figure 24 shows an example of a hydrothermal system. This power system is characterised by a mix of hydroelectric and geothermal based production units. Electricity production from geothermal energy follows the same principles as for any other conventional steam based electricity production, yet geothermal energy is free and for short time considerations there is an unlimited supply and it is non-storable. Thus, geothermal plants were set to have generation costs of 0, and the optimal policy is to operate at full capacity. Consequently, it will not be the focal point in subsequent chapters (Pétursson, Linnet, Jónasson, & Hreinsson, 2013; Sveinsson & Linnet, 2012).

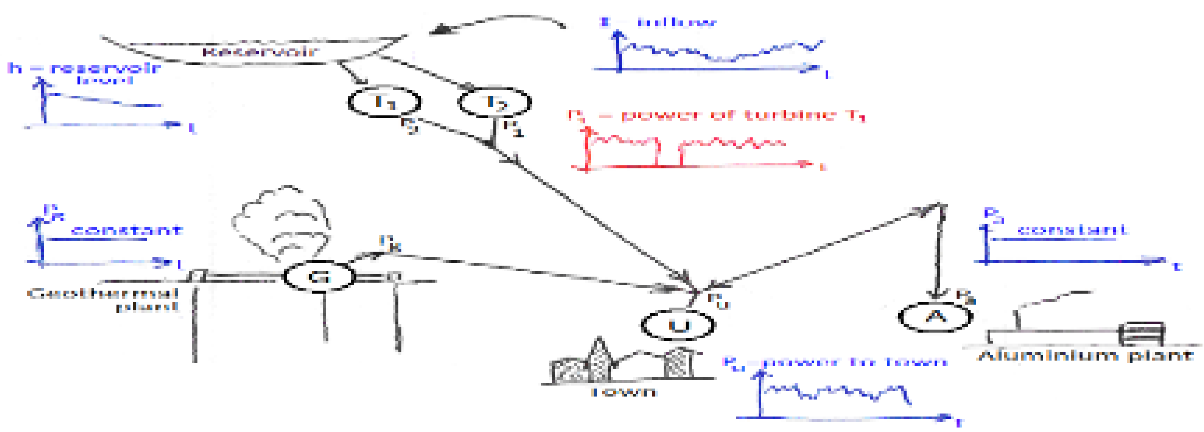

Figure 24: A hydro-thermal system
(Pétursson, 2012)

Chapter 7 - Dynamic Programming

To achieve an optimal hydro operation strategy in a hydro dominated system, efficient water resources management is needed. A recognised method is to combine all reservoir volumes and power plants into one, thus the inflow into the corresponding reservoir becomes the total inflow into a single reservoir in the initial system. Through this action the typical feature of the inflow evolves into a mix of inflow characteristics within one single reservoir (Sveinsson & Linnet, 2012).

Dynamic programming is used to determine the water values for the water stored in the reservoirs, to achieve an optimal hydro operation strategy, and to explore potential arbitrage possibilities. That is, the opportunity cost of selling water today versus selling it in the future is determined via the framework of dynamic programming through the introduction of a state variable (Steeger et al., 2014).

7.1 Discrete Dynamic Programming

The discrete Markov decision model is utilised in this section and has the following outline: in every period t, an operator observes the state of an economic system, s_t takes an action x_t, and acquires f (s_t,x_t), which is contingent upon the state of the system and the action.

The probability distribution state of the next period, subject to all presently accessible information, hinges on the present state and the operator´s actions, which are then given by the following expression:

$$\Pr(s_{t+1} = s'|s_t = s, x_t = x, other\ information\ at\ t) = P(s'|s,x)$$

In other words, the operator searches for a sequence of policies $\{x_t^*\}$ that recommend the action x_t=x_t^* (s_t), which ought to in any given state and period maximise the present value of the current and expected future rewards over a time horizon T, discounted by a definite factor δ for each period.

Dynamic programming is a policy that uses a value function to estimate the future effect of present choices. Moreover, it is based on the principle of optimality, indicating that whatever the original state and choices are, the remaining decisions must constitute an optimal policy with regard to the state resulting from the first decision.

$V_t(s)$, indicates the maximum attainable sum of the current and expected future rewards, given that the system is in state, s in period t, then the principle of optimality indicates that the value functions V_t: S -> $\mathfrak{R}$ must fulfil the following expression:

$$V_t(s) = \max_{x \epsilon X(s)} \left\{ f(s,x) + \delta \sum_{s' \in S} P(s'|s,x) V_{t+1}(s') \right\}, s \in S, t = 1,2, \dots, T.$$

In fact, the Bellman equation captures the crucial problem faced by a dynamic future regarding the optimising operator. That is, it captures the need to optimally balance an immediate reward f $(s_{t,} x_t)$ against estimated future rewards $\delta E_t V_{t+1}(s_{t+1})$ (Miranda & Fackler, 2002; Powell, 2012)

7.2 Dynamic Programming Problem

Simply put, there are two main challenges in the operation of hydroelectric units, including uncertainty in the development of electricity prices over time, and inflow of water into a reservoir. The challenges reflect the fact that the decision itself is based on buying and selling electricity in order to maximise profit, considering uncertainty in inflow and prices, as well as specific physical constraints of the storage system (Lamontagne, 2015; Löhndorf et al., 2013). The problem of buying and selling electricity through a subsea power cable between Iceland and the UK will be addresses in order to explore the arbitrage possibility.

The total energy demand (in MWh) in Iceland must be met at all times from either geothermal or hydropower energy, or energy from the grid. The demand is deterministic and estimates the electricity consumption of Iceland for the period between 2015 and 2050, using data from the Icelandic Energy Forecasts Committee. In order to show the effect of a market interconnector, three scenarios are presented for estimated electricity consumption, low, main, and high forecasts.

The weekly average of the typical daily electricity prices in the UK is given as p, for each half-hour period, and is log-normally distributed. There are five elements that are used to present the problem, including states, actions, exogenous information, transition and objective function, and endogenous variables.

7.2.1 Model Assumptions

To make the problem logically manageable, the following assumptions are introduced.

Price taker: The operator is a price taker in the electricity market. This means the operation of the energy storage will not have an effect on the electricity price.

Single market: Only one-type of electricity market is considered, which means the time interval between the sequential stages to make a decision is one specific constant. These assumptions conceptually simplify the problem and allow the analytical solution to be described in a compact way (Qin et al., 2012).

In order to have a simple model, demand is considered to be deterministic, and only inflows are assumed to be stochastic. For hydropower, only an aggregated system consisting formally of one plant and one reservoir will be considered. Moreover, geothermal electricity production is exogenous in the model (Førsund, 2007).

7.2.2 State Variable

Only one state variable is added to the optimisation problem; the reservoir state S_t . The focus is on how the hydro producer allocates the total weekly inflow, given the limitations of reservoir size S_{max}. The reservoir state variable is a function of past inflows and represents a forecast of future inflows.

7.2.3 Exogenous Information Process

The exogenous information process is defined as the electricity demand in Iceland. Market producers know the parameters of the demand function in advance (i.e., the profile of the demand is deterministic). As the area is self-sufficient, this demand is completely fulfilled by the power produced in the system. The exogenous information process is defined as the weekly average of typical daily electricity prices in the UK, for each half-hour period. Geothermal electricity production is defined to constitute the exogenous information process.

7.2.4 State Transition

The resource transition probability of the Markov process is represented by $\emptyset(s_{t+1} | s_t)$. The transition function describes the evolution of the system over time and can be expressed mathematically as:

$$s_{t+1} = s^M(s_t, x_t, w_{t+1})$$

It should be noted however, that, s_t is assumed to be fully known at time t; x_t is a decision that depends on the known information in s_t, while w_{t+1} is random at time t (Powell, 2012). The weekly transition function in this model is given by the following expression:

$$s_{t+1}^g = s_t + f_t - d_t + x_t^{(b)g} - x_t^{(s)g}$$

Where s_t is the reservoir state, f denotes the inflow, d is the discharge from the reservoir to meet the total energy demand (MWh) in Iceland, and $x^{(s)}$ is the amount of power (MWh) sold or purchased $x^{(b)}$.

7.2.5 Endogenous Variables

The endogenous variables are the buying price p^b and selling price p^s, which are explained further below.

7.2.6 Objective Function

The objective of the Icelandic social planner in this market is to maximise its expected weekly profits through an efficient bidding and storage operation. The objective function is defined by:

$$\max_{p^s,p^b} \pi = \left(\left[\int_{p^s}^{M} pf(p)dp\right](1-\theta)x^{(s)}\right) - \left(\left[\int_{0}^{p^b} pf(p)dp\right](1+\theta)x^{(b)}\right)$$

$$0 \le p \le M$$

Thus, p represents average prices that are log-normally distributed, θ is the loss in power flow that is transmitted through the interconnector, and $x^{(s)}$ is the amount of power (MWh) sold or purchased $x^{(b)}$.

The value of being in state s_{t+1} is given by:

$$V(s_{t+1}) = \left\{\begin{array}{ll} V\left(s_t + f_t - d_t + x_t^{(b)}\right) & P_r(0 \le p < p^b) \\ V(s_t + f_t - d_t) & P_r(p^b \le p < p^s) \\ V\left(s_t + f_t - d_t - x_t^{(s)}\right) & P_r(p^s \le p) \end{array}\right\}$$

While the state transition can be written as:

$$s_{t+1}^{g} = s_t + f_t - d_t + x_t^{(b)g} - x_t^{(s)g}$$

The expected value of $V(s_{t+1})$ is given by:

$$E\left(V(s_{t+1})\right) = V\left(s_t + f_t - d_t + x_t^{(b)}\right) * P_r(0 \le p < p^b) + V(s_t + f_t - d_t) * P_r(p^b \le p < p^s) + V\left(s_t + f_t - d_t - x_t^{(s)}\right) * P_r(p^s \le p)$$

Further, the value of being in state s_t given by optimality equations can be written as:

$$V(s_t) = \max_{p^s,p^b} \left(\left[\int_{p^s}^{M} pf(p)\,dp \right] (1-\theta)\, x^{(s)} \right) - \left(\left[\int_{0}^{p^b} pf(p)\,dp \right] (1+\theta) x^{(b)} \right) + \beta E\big(V(s_{t+1})\big)$$

7.2.7 Solving the Model

The first-order condition for this problem (i.e., for buying and selling power (MWh) from Iceland) is then given by the following expression:

$$\frac{\partial V}{\partial p^b} = -(1+\theta)x^{(b)}p^b f(p^b) + \beta(V(+1) * f(p^b) - V(0) * f(p^b))$$

$$-(1+\theta)x^{(b)}p^b + \beta\big(V(+1) - V(0)\big) = 0$$

$$p^b = \frac{\beta \Delta V_t}{(1+\theta)x^{(b)}}$$

$$\frac{\partial V}{\partial p^s} = -(1-\theta)\,x^{(s)}p^s f(p^s) + \beta(V(-1) * f(p^s) - V(0) * f(p^s))$$

$$-(1-\theta)x^{(s)}p^s + \beta\big(V(-1) - V(0)\big) = 0$$

$$p^s = \frac{\beta \Delta V_t}{(1-\theta)x^{(s)}}$$

By allocating the hydro production in order to maximise its expected weekly profits, the buying price p^b and selling price p^s will be equalised with the discounted stream of water value (indicated by the discount factor β).

7.3 Overall Solution from the Dynamic Programming

To demonstrate the overall solution the Icelandic social planner's decision will be explained based on efficient bidding and storage operation in order to maximise the expected weekly profits.

As a supplier that acts as a price taker in a competitive electricity market, optimal outcome is realised by setting the bid equal to the marginal costs. In contrast, whereas thermal power plants can relate their marginal costs to the cost of fuel, hydropower producers obtain their water for free. Accordingly, hydroelectric generation has a very low variable cost of operation, typically less than 0.5 cents/kWh compared to 3 cents/kWh for gas and coal plants. As long as the storage volume is restricted to less than the amount of water that is necessary to satisfy demand during all periods, there is a constraint on the supply of energy. Hence, for the Icelandic social planner, computing the generation costs requires computing the shadow price of stored water (i.e., the water value; Alnæs, Grøndahl, Fleten, & Boomsma, 2015; Johnsen, Verma, & Wolfram, 1999).[19]

The Icelandic social planner bids a price for energy capacity under a range of supply and demand conditions, selecting the supply bid to maximise profit based on the estimate of the residual demand curve, which is considered to be deterministic within the problem (Cramton, 2004). The optimal supply bidding in the day-ahead market is conditional on the water value, together with the loss in power flow that is transmitted through the interconnector and the discount factor. In a perfectly competitive market the Icelandic social planner should simply bid a price for electricity that reflects the discounted water value. If the social planner bids a price lower than or equal to the market price (i.e., if the market price is higher than or equal to the discounted water value) it is dispatched. In contrast, if the social planner bids higher than the market price (i.e., if the discounted water value is higher than the market price) it does not get dispatched and thus ends up with more storage at the end of the period. Higher storage levels have a tendency to lower the water value at a plant, hence bringing it in line with the rest of the market (Johnsen et al., 1999). In addition, the Icelandic social planner offers to purchase electricity at a market price that is lower than the discounted water value.

Determining the water value is far from easy, as the value of extra units of water in a reservoir, the marginal water value, depends upon more than simply future price expectations. It is influenced by the current reservoir level, local inflow expectations, and the size of the reservoir, compared to its average inflow and production capacity (Alnæs et al., 2015). In reality, the profit maximisation problem for a hydropower producers is complicated by uncertainty concerning both demand and inflows. Yet, with large storage small changes in inflows do not drastically change the water value. As a result, water value may be assumed to be constant over short periods, for example a week in systems with sufficient storage (Johnsen et al., 1999). Allocating hydro production in order to maximise its expected weekly profits based on historic weekly inflow is therefore realistic. Given the setup of the problem, as outlined in Section 7.2, a simulation of the model provides updated water values to use throughout

[19] For the purpose of simplification, geothermal plants were set to have generation costs of 0, as geothermal energy is free and for short time considerations there is an unlimited supply and is non-storable.

the week, and accordingly the social planner makes a decision based on a one-week ahead forecast.

Taken together, there are two interlinked issues in hydropower scheduling: i) the determination of the water value; and ii) the optimal bidding in the day-ahead market conditional on the water value. The conceptual solution using stochastic dynamic programming is already in place. The actual implementation runs into the Achilles' heel of dynamic programming, namely the curse of dimensionality. Since the lack of time didn´t allow for all aspects of the problem to be implemented and manipulated in order to solve the problem in the memory of an ordinary PC, it is suggested that the problem should be expanded within this chapter, which is relatively simple but still sufficient to make the point.

A simplified version of the problem has been implemented and will be described in the next section. The bidding strategy will be assessed along the lines of a 'battery problem', i.e. fixed storage with a stochastic inflow and fixed domestic demand interacting with the UK market through a day-ahead auction.

7.3.1 Simplified Version of the Problem

The Icelandic reservoir can be viewed as a battery, storing power in the form of water when demands are low and producing the maximum amount of power during daily and seasonal periods. This adaptability of hydropower makes it possible to rapidly adjust the electricity output to changes in demand. This makes it valuable for meeting peak loads and for serving in a reserve capacity to protect power system reliability and stability. It should be noted, however, that the problem at the moment is that even hydropower is not instant. This is because water takes time to flow through the enormous networks of pipes and turbines to reach the correct speed and provide stable power to the grid at the correct frequency of alternating current. To become a green battery, power plants would need to be started and stopped much more frequently, and then, the problem of load fluctuations would increase significantly (Askja Energy Partners, 2014b; Climate Home, 2015; The USGS Water Science School, 2016; U.S. Army Engineer Institute for Water Resources, 2009).

In this scenario, the battery system enters the wholesale electricity market as a supplier during its discharge cycles and as a consumer during its charge cycles. Given the storage with a stochastic inflow and fixed domestic demand interacting with the UK market through a day-ahead auction, the operator has to decide what the best supply and demand bidding strategy is in order to achieve an optimal operation strategy and to explore the potential arbitrage opportunity (Mohsenian-Rad, 2015).

7.3.1.1 Underlying Structure of the Model

The underlying structure of the model will first be described. The electricity prices are hourly reference prices in €/MWh from the day-ahead auction market in the UK for the period of June 6th, 2014 to September 7th, 2016. The implications of the model consist of two Julia codes, with one code doing a wide search with a coarse grid for prices and the other code carrying out a narrow search with a finer grid.

For this setup, the selling and buying behaviour will be assessed in detail by using the empirical distribution of prices. When an Icelandic social planner wants to buy more than one unit and when the units have declining marginal values, a bidder generally has an incentive to reduce demand (to bid less than the value for some units), and the results below illustrate how strong this incentive can be. A total competitive equilibrium allocation must maximise the total value (Milgrom, 2004). However, it should be indicated that the marginal value of a unit of electricity is the incremental value that could be obtained by an operator if the operator were to own that unit in addition to the operator's current holdings. In general, an operator´s goal is to determine what sets of electricity should be bought and sold to maximise the surplus - the value of the resulting optimal allocation less the cost of the goods plus any revenues earned from sales. In addition, the results of the optimisation describe the probability of buying and selling electricity, given the current state of the system (i.e., the energy storage).

The relationship between the buy and sell prices and the marginal values can be explained through the following three statements: First, the marginal value of any non-arbitrage opportunity in any optimal transaction is at least the buy price; second, the marginal value of any arbitrage opportunity when the agent does not sell in any optimal transaction is at least the (buy) sell price; and third, the marginal value of any arbitrage opportunity that an agent sells in any optimal transaction is at most the sell price (Wellman, Greenwald, & Stone, 2007).

The optimal supply and demand bidding in the day-ahead market is conditional on the loss of power flow that is transmitted through the interconnector and the discount rate, which is described in Table 4. Moreover, a penalty for buying if there is no storage and for selling if there is no delivery is introduced. A complete detailed description of the model's underlying structure can be found in Appendices A and B.

Table 4: Model parameters

```
r = 0.02;             # discount rate
ß = 1/(1+r);          # discount factor
l_in  = 0.1;          # energy loss in
l_out = 0.1;          # energy loss out
# need a penalty when storage is out-off bounds
ŋ_b =  5*pavg;        # penalty for buying, no storage
ŋ_s = 25*pavg;        # penalty for selling, no delivery
amax =  np;           # number of actions
smax =  49;           # number of states
tmax =   6;           # number of bidding periods
```

7.3.2 Results of the Optimisation

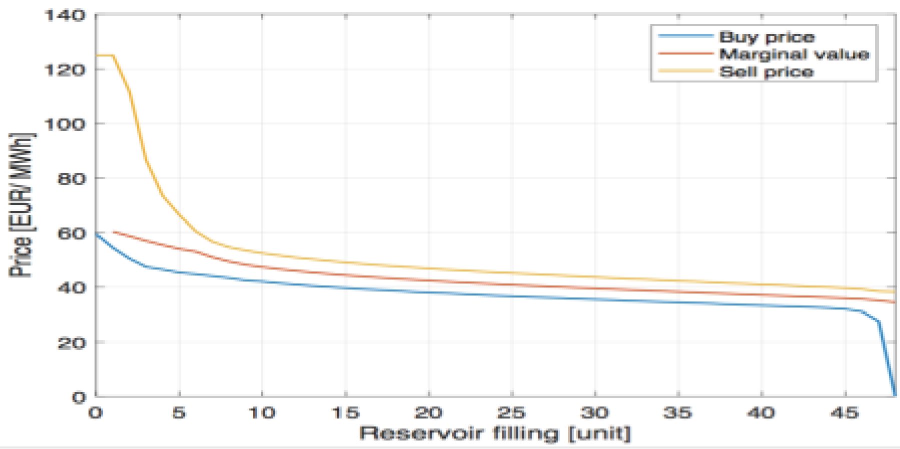

Figure 25: Buy price, sell price and marginal value of an electricity given the current state of the system

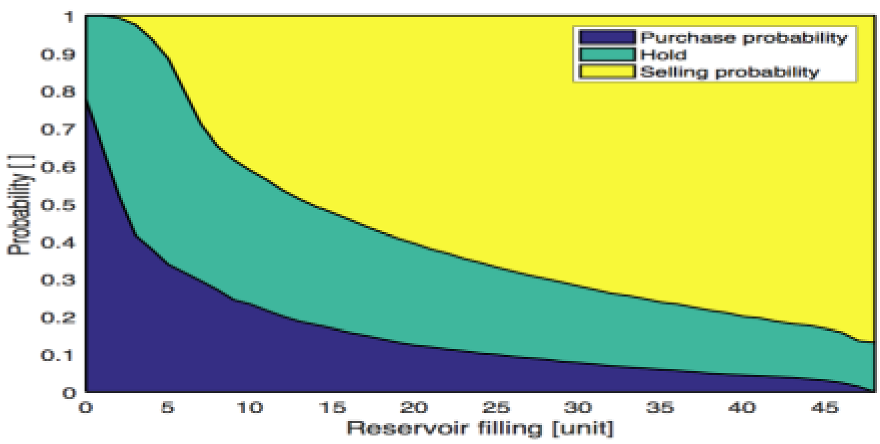

Figure 26: The probability of buying, selling or holding given the current state of the system

Figure 25 and Figure 26 capture the basic results of the stochastic dynamic model. Figure 25 clarifies the main essence of arbitrage, the bid price that must be sold at a higher price than what it was bought with. In addition, the figure combines the relationship between the buying and selling of electricity and the marginal value of a unit of electricity, considering the physical constraints of the storage system. A declining buy price illustrates the interaction between the marginal value and the reservoir filling. An Icelandic social planner has an incentive to reduce demand, that is, to bid less than the value for some units when the units have declining marginal values. Figure 26 shows the probability of buying, selling, or holding, taking into account the current state of the storage system. It can be seen that the selling probability increases when there is increase in water level behind the dam (increase in reservoir filling); in addition, the purchase probability is lower when there is higher reservoir level. The figure also shows the probability of holding, that is, the probability that the Icelandic social planner neither buys nor sells electricity. This happens when the market price is higher than the price that the Icelandic social planner is willing to pay and when the market price is lower than the price that the social planner is willing to sell at.

Taken together, the results of the optimisation illustrate the value of energy storage. Specifically, the value is equal to the profit that can be made by buying and selling electricity, resulting from optimal allocation. The complete results can be found in Appendix C.

7.3.3 Future Work

As mentioned, the dynamic programming model presented in this chapter needs more work in order to give more complete and accurate results. Some possible extensions include both price and inflows as stochastic variables for a system that would resemble a real-world scenario (Vistica, 2012). The implementation of a code with a focus on dynamics would be preferred. This would allow, for example, the cooperation possibilities of hydropower, wind power, and geothermal trading decisions in the intraday market. This thesis has focused on geothermal and hydropower production in Iceland; although, there is also a substantial wind power potential.

Chapter 8 - Conclusions

This study has examined the impact of building a subsea power cable between Iceland and the UK, in order to better understand the costs and benefits associated with the international liberalisation of Iceland's electricity market. One part of the thesis examined the simulation results of large-scale simulation model for the European energy market (LIBEMOD), where such a cable has been implemented. The model accounts for the total energy produced, as well as the total energy consumed in each of the EU-30 model countries.

The second part of the thesis mainly focused on the decision concerning buying and selling electricity through a subsea power cable between Iceland and the UK to explore the arbitrage possibility, which provides a thorough description of the value of the adaptability of Icelandic hydropower. There are two interlinked issues in hydropower scheduling: i) determination of the water value, and ii) optimal bidding into the day-ahead market conditional upon the water value, which were identified theoretically. A conceptual solution using stochastic dynamic programming was provided and was supported by a simplified version of the problem along the lines of a battery problem (i.e., a given storage with a stochastic inflow and fixed domestic demand interacting with the UK market through a day-ahead auction). Since the lack of time didn´t allow for all the problem to be implemented and manipulated in order to solve the problem in the memory of an ordinary PC, it was suggested that the problem should be expanded within Chapter 7, which although relatively simple is still sufficient to make the point.

It has been demonstrated in this study that building a 900 MW subsea power cable between Iceland and the UK would increase the production of electricity significantly in Iceland due to higher prices. This would also result in significant redistribution of welfare from consumers to producers, and increase the welfare of the energy sector in Iceland by €64 million per year, in contrast to the scenario of no cable. Additionally, the connection to cheap green power supplies is beneficial to the UK, as economic welfare in the UK increased by €41 million per year for the 900 MW cable scenario in contrast to no cable. Moreover, higher investment in a 1471 MW cable increases the total economic welfare for both countries, together with an increase in total producer and consumer surplus.

References

Alnæs, E. N., Grøndahl, R. B., Fleten, S.-E., & Boomsma, T. K. (2015). Insights from Actual Day-Ahead Bidding of Hydropower. *International Journal of Sustainable Energy Planning and Management*, *07*, 37–58.

Arnarson, H. (2014). Changing Markets - Changing Demands.

Arnarson, H. (2016). Landsvirkjun's Annual Meeting. Reykjavík: Landsvirkjun.

Arnarson, H., & Larusson, R. (2016). Landsvirkjun Financial Statements 2015, (February).

Ásgeirsdóttir, M. O. (2011). Power markets and possible power export from Iceland. Retrieved February 25, 2015, from http://skemman.is/stream/get/1946/7303/19505/1/Margr%C3%A9t_Ormslev_ritger%C3%B0.pdf

Askja Energy. (2015). The Hydro and Geothermal History. Retrieved October 25, 2015, from http://cc.bingj.com/cache.aspx?q=public+utility+firm+called+Rafmagnsveita+Reykjav%C3%ADkur&d=4830495373201995&mkt=nb-NO&setlang=en-US&w=HJCjeQnUOXaUp-02y6s3cGk3Y9Fz1Zkh

Askja Energy Partners. (2014a). IceLink Offers Flexibility Rather Than Baseload Power.

Askja Energy Partners. (2014b). IceLink Offers Flexibility Rather Than Baseload Power.

Askja Energy Partners. (2014c). Norway´s Positive Experience from Interconnectors and Open Electricity Market.

Aune, F. R., Dalen, H. M., & Hagem, C. (2012). Implementing the EU renewable target through green certificate markets. *Energy Economics*, *34*(4), 992–1000. http://doi.org/10.1016/j.eneco.2011.07.006

Aune, F. R., Golombek, R., Moe, A., & Rosendahl, K. E. (2015). Liberalizing Russian Gas Markets : An Economic Analysis, *36*, 1–36.

Aune, F. R., Golombek, R., & Tissier, H. H. Le. (2015). *Phasing out nuclear power in Europe*. Oslo.

Authority), O. (National E. (n.d.). Energy Statistics. Retrieved February 26, 2015, from http://www.nea.is/the-national-energy-authority/energy-statistics/,

Barbour, E. (2013). *An Investigation into the potential of Energy Storage to tackle Intermittency in Renewable Energy Generation Doctor of Philosophy*. The University of Edinburgh.

Barbour, E., Wilson, G., Hall, P., Radcliffe, J., Barbour, E., Wilson, G., … Radcliffe, J. (2016). Can negative electricity prices encourage inefficient electrical energy storage devices?, *7233*. http://doi.org/10.1080/00207233.2014.966968

Braun, S. (2016). Hydropower Storage Optimization Considering Spot and Intraday Auction Market. *Energy Procedia*, *87*, 36–44. http://doi.org/10.1016/j.egypro.2015.12.355

Bunn, D., Andresen, A., Chen, D., Westgaard, S., & Place, S. (2012). Analysis and Forecasting of Electricty Price Risks with Quantile Factor Models, (September), 1–32.

BusinessDictionary. (n.d.). What is a cost benefit analysis (CBA)? definition and meaning. Retrieved June 12, 2016, from http://www.businessdictionary.com/definition/cost-benefit-analysis-CBA.html

Climate Home. (2015). Norway cranks up plan to be Europe's "green battery." Retrieved July 16, 2016, from http://www.climatechangenews.com/2015/07/27/norway-cranks-up-plan-to-be-europes-green-battery/

Cramton, P. (2004). Competitive Bidding Behavior in Uniform-Price Auction Markets. *Published in the Proceedings of the Hawaii International Conference on System Science*.

De Nooij, M. (2011). Social cost-benefit analysis of electricity interconnector investment: A critical appraisal. *Energy Policy*, *39*(6), 3096–3105. http://doi.org/10.1016/j.enpol.2011.02.049

Department of Energy and Climate Change. (2013). Digest of UK energy statistics (DUKES). Retrieved February 26, 2015, from https://www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes

Department of Energy and Climate Change. (2016). UK Energy Statistics, 2015 & Q4 2015.

Diffney, S., Gerald, J. F., & Valeri, L. M. (2009). Investment in electricity infrastructure in a small isolated market: the case of Ireland. *Oxford Review of Economic Policy*, 469–487.

Edmunds, R. K., Cockerill, T. T., Foxon, T. J., Ingham, D. B., & Pourkashanian, M. (2014). Technical benefits of energy storage and electricity interconnections in future British power systems. *Energy*, *70*, 577–587. http://doi.org/10.1016/j.energy.2014.04.041

EFTA Surveillance Authority. (2014). Case No: 76459 Event No: 734062 Decision No: 543/14/COL, *705821*(705821), 1–35.

Ekins, P., Strachan, N., & Usher, W. (2013a). The UK energy system in 2050 : Comparing Low-Carbon , Resilient Scenarios. *UKERC Research Report*, (UK Energy Research Centre).

Ekins, P., Strachan, N., & Usher, W. (2013b). *The UK energy system in 2050 : Comparing Low-Carbon , Resilient Scenarios*.

Energy Market Authority. (2013). National report 2013 to the Agency for the Cooperation of Energy Regulators and to the European Commission., (December), 1–68. Retrieved from http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National Reporting 2013/NR_En/C13_NR_Finland-EN.pdf

Eurostat. (2014). Europe 2020 indicators - climate change and energy.

Evans, P. C. (2002). *Liberalizing Global Trade in Energy Services*. WASHINGTON, D.C.: The AEI Press.

Eyjan.pressan.is. (2015). Noregur væri miklu fátækara land ef hugarfarið þar væri eins og á Íslandi. Retrieved February 25, 2015, from http://eyjan.pressan.is/frettir/2015/02/08/noregur-vaeri-miklu-fataekara-land-ef-hugarfarid-thar-vaeri-eins-og-a-islandi/

Fleten, S., & Kristoffersen, T. K. (2007). Stochastic programming for optimizing bidding strategies of a Nordic hydropower producer, *181*, 916–928. http://doi.org/10.1016/j.ejor.2006.08.023

Førsund, F. R. (2007). *Hydropower Economics*.

Frischsenteret. (n.d.). About LIBEMOD. Retrieved February 26, 2015, from http://www.frisch.uio.no/ressurser/LIBEMOD/About the model/

Frischsenteret. (2014). Technical documentation LIBEMOD 2009.

Füss, R., Mahringer, S., & Prokopczuk, M. (2015). Electricity derivatives pricing with forward-looking information. *Journal of Economic Dynamics and Control*, *58*, 34–57. http://doi.org/10.1016/j.jedc.2015.05.016

Geels, F. W., Kern, F., Fuchs, G., Hinderer, N., Kungl, G., Mylan, J., … Wassermann, S. (2016). The enactment of socio-technical transition pathways : A reformulated typology and a comparative multi-level analysis of the German and UK low-carbon electricity transitions (1990 – 2014). *Research Policy*, *45*(4), 896–913. http://doi.org/10.1016/j.respol.2016.01.015

Geographical Magazine. (2014). A heated debate.

Giesbertz, P., & Mulder, M. (2008). Economics of Interconnection: the Case of the Northwest European Electricity Market. *International Association for Energy Economics*, pp. 18–19.

Golombek, R., Arne, K., & Kittelsen, S. A. C. (2013). Is electricity more important than natural gas ? Partial liberalizations of the Western European energy markets. *Economic Modelling*, *35*, 99–111. http://doi.org/10.1016/j.econmod.2013.06.023

Golombek, R., Greaker, M., & Kittelsen, S. A. C. (2013). Carbon Caputre and Storage Technologies in the European Power Market. *Energy Economics*, *32*, 209–238. http://doi.org/10.5547/ISSN0195-6574-EJ-Vol32-No3-8

Golombek, R., Kittelsen, S. A. C., & Rosendahl, K. E. (2012). Price and welfare effects of emission quota allocation. *Energy Economics*, *36*(March), 568–580. http://doi.org/10.1016/j.eneco.2012.11.006

Hagfræðistofnun Háskóla Íslands. (2013). Þjóðhagsleg áhrif sæstrengs. Retrieved February 25, 2015, from http://www.atvinnuvegaraduneyti.is/media/saestrengur-til-evropu/Skyrsla-HHI-26-juni-2013.pdf

Hagstofa Íslands. (n.d.). Hagstofa Íslands - Energy. Retrieved February 26, 2015, from http://www.statice.is/default.aspx?pageid=2185&templateid=8

Heimisson, B. (2014). Improved frequency control strategies for geothermal power plants, Chalmers University of Technology.

Higgins, A. (2013). Iceland Weighs Exporting the Power Bubbling From Below. Retrieved February 25, 2015, from http://www.nytimes.com/2013/02/21/world/europe/iceland-weighs-exporting-the-power-bubbling-from-below.html

Hreinsson, E. B. (2007). Climate Change and its Impact on Optimization, Simulation and Expansion Strategies in a Small Renewable and Hydro-thermal Power System. *Universities Power Engineering Conference, 2007. UPEC 2007. 42nd International*.

Hreinsson, E. B. (2008). Renewable Energy Resources in Iceland – Environmental Policy and Economic Value. *Nordic Conference on Production and Use of Renewable Energy 9-11 of July, 2008, Vaasa, Finland*, (October), 1–10.

Hreinsson, E. B. (2013). Operations Modeling in the Iceland Hydro Dominated Power System. *Power Engineering Conference (UPEC), 2013 48th International Universities'*, (Conference Paper).

Huuki, H. (2014). Reserve allocation of hydropower producer in a hydro-thermal-intermittent power electricity, 1–36.

Iceland Geothermal. (n.d.). Retrieved from http://www.icelandgeothermal.is/iceland-geothermal/geothermal-development/

Iceland Review. (2016). World's Highest Per Capita Electricity Usage in Iceland.

Investopedia Staff. (n.d.). What is arbitrage.

IRENA. (2015). Renewable Power generation Costs in 2014, (January).

Íslandbanki. (2010). Iceland Geothermal Energy Market Report, (April), 36.

Johnsen, T. A., Verma, S. K., & Wolfram, C. (1999). Zonal Pricing and Demand-Side Bidding in the Norwegian Electricity Market. Retrieved from http://www.ucei.berkeley.edu/pubs-pwp.html\nhttp://www.ucei.berkeley.edu/PDFDown.html\nhttp://dsm.iea.org/NewDSM/Prog/Library/frame.asp?RNDKey=wkwsjtvjbvdwibt

Jónsson, S. A., Bjarnason, M., Hannesson, S., Davies, G., & Martin, M. (2016). *Raforkusæstrengur milli Íslands og Bretlands, kostnaðar- og ábatagreining*. Retrieved from https://www.atvinnuvegaraduneyti.is/media/Acrobat/Raforkusaestrengur-milli-Islands-og-Bretlands-kostnadar-og-abatagreining.pdf

Ketilsson, J., Petursdottir, H. T., Thoroddsen, S., Oddsdottir, A. L., Bragadottir, E. R., Gudmundsdottir, M., & Johannesson, G. A. (2015). Legal Framework and National Policy for Geothermal Development in Iceland, (April), 19–25.

Kristjánsdóttir, H. (2014). *Economics and Power-intensive Industries* (1st ed.). Springer International Publishing.

Lamontagne, J. R. (2015). *Representation of Uncertainty and Corridor DP for Hydropower Optimization*. Cornell University.

Landsnet. (n.d.-a). About Landsnet.

Landsnet. (n.d.-b). Iceland´s electricity market. Retrieved February 25, 2015, from http://landsnet.is/english/transmissionandmarket/icelandselectricitymarket/

Landsnet. (n.d.-c). Landsnet´s grid.

Landsnet. (n.d.-d). Market Participants. Retrieved from http://www.landsnet.is/english/transmissionandmarket/icelandselectricitymarket/marketparticipants/

Landsvirkjun. (n.d.). History. Retrieved October 15, 2015, from http://www.landsvirkjun.com/company/history

Landsvirkjun. (2016a). Nordural and Landsvirkjun Reach Agreement on Terms for Power Contract Extension.

Landsvirkjun. (2016b). Submarine Cable to Europe. Retrieved from http://www.landsvirkjun.com/researchdevelopment/research/submarinecabletoeurope

Landsvirkjun. (2016c). Submarine Cable to Europe.

Lockwood, M. (2013). The political sustainability of climate policy : The case of the UK Climate Change Act. *Global Environmental Change*, *23*(5), 1339–1348. http://doi.org/10.1016/j.gloenvcha.2013.07.001

Löhndorf, N., Minner, S., & Wozabal, D. (2013). Optimizing Trading Decisions for Hydro Storage Systems Using Approximate Dual Dynamic Programming, (March 2016). http://doi.org/10.2307/23481798

Lúthersson, A. (n.d.). Geothermal Energy Iceland Perspective.

Maciejowska, K., Nowotarski, J., & Weron, R. (2014). Probabilistic forecasting of electricity spot prices using Factor Quantile Regression Averaging. *International Journal of Forecasting*. http://doi.org/10.1016/j.ijforecast.2014.12.004

Manzano-agugliaro, F., Montoya, F. G., Gil, C., Alcayde, A., Gómez, J., & Ba, R. (2011). Optimization methods applied to renewable and sustainable energy : A review, *15*, 1753–1766. http://doi.org/10.1016/j.rser.2010.12.008

Milgrom, P. R. (2004). *Putting Auction Theory to Work*. Cambridge University Press.

Miranda, M. J., & Fackler, P. L. (2002). *Applied Computational Economics and Finance*. The MIT Press.

Mohsenian-Rad, H. (2015). Optimal Bidding, Scheduling, and Deployment of Battery Systems in California Day-Ahead Energy Market. *IEEE Transactions on Power Systems*, 442 – 453.

Moody´s. (2015). Rating Action: Moody´s revises Landsvirkjun outlook to positive from stable.

National Energy Authority. (2006). Energy in Iceland - HISTORICAL PERSPECTIVE, PRESENT STATUS, FUTURE OUTLOOK, *Second edi*.

National Energy Authority of Iceland. (2015a). Íslenska raforku kerfið., *Viðauki 87*.

National Energy Authority of Iceland. (2015b). *OS-2015-T004-02: Electricity Generation per capita 1969-2014*.

National Energy Authority of Iceland. (2015c). *Raforkuspá 2015 – 2050*. Reykjavík.

National Energy Authority of Iceland. (2016). *OS-2016-T002-01: Primary energy use in Iceland 1940-2015 [data file].* Reykjavík.

National Energy Authority of Iceland, The Artic University of Norway, Danish Energy Agency, Foroese Earth and Energy, Directorate, Shetla Islands Council -Economic Development Service, & Greenland Innovation Centre. (2016). *North Atlantic Energy Network*.

Nord Pool. (n.d.). N2EX day-ahead market. Retrieved July 17, 2016, from http://www.nordpoolspot.com/TAS/N2EX-day-ahead-market/

Ólafsson, L., Þorsteinsson, Í., Pétursdóttir, H. Þ., & Eggertsson, H. (2011). *Report on regulation and the electricity market 2010 Iceland*. Reykjavík. http://doi.org/978-9979-68-292-9

Pétursson, G. G. (2012). Modelling Wind-Integrated Hydro-Thermal Power Systems, (Unversity of Iceland).

Pétursson, G. G., Linnet, Ú., Jónasson, K., & Hreinsson, E. B. (2013). A Comparison of two Hydro Scheduling Algo- rithms , SDDP and LpSim. *Power Engineering Conference (UPEC), 2013 48th International Universities'*, (IEEE). http://doi.org/10.1109/UPEC.2013.6714950

Phan, S., & Roques, F. (2015). Is the depressive effect of renewables on power prices contagious? A cross border econometric analysis. *CEEM Working Paper 2015-16*, (April).

Pollitt, M. G. (2010). UK Renewable Energy Policy since Privatisation, (January).

Powell, W. B. (2012). A unified framework for stochastic and dynamic programming. *The Informs Computing Society Newsletter*.

Qin, J., Sevlian, R., Varodayan, D., & Rajagopal, R. (2012). Optimal Electric Energy Storage Operation, *94305*, 1–6.

Ragnarsson, Á. (2015). Geothermal Development in Iceland 2010-2014, *2010*(April), 19–25.

RenewableEnergyWorld.com. (n.d.). Geothermal Power and Electricity Production.

Salo, A. (2015). Demand and wind power scenarios for predicting power prices in a transmission-constrained system.

Schneider, E. (1962). *Pricing and Equilibrium: An Introduction to Static and Dynamic Analysis*. London: Routledge.

Solibakke, P. (2011). *Market Risk Management with Stochastic Volatility Models, Risk Management in Environment, roduction and Economy, Dr. Matteo Savino (Ed.)*. In Tech.

Spiecker, S., Vogel, P., & Weber, C. (2013). Evaluating interconnector investments in the north European electricity system considering fl uctuating wind power penetration. *Energy Economics*, *37*, 114–127. http://doi.org/10.1016/j.eneco.2013.01.012

Steeger, G., Barroso, L. A., Member, S., & Rebennack, S. (2014). Optimal Bidding Strategies for Hydro-Electric Producers : A Literature Survey, *29*(4), 1758–1766.

Sveinsson, Ó. G. B. ;, & Linnet, Ú. (2012). Longterm hydro and geothermal reservoir operation. *SIMS 2012 : The 53rd Scandinavian Conference on Simulation and Modeling, Organized by Orkustofnun, Reykjavík 4-6 October, 2012*.

The Artic University of Norway. (2016). First steps towards a North Atlantic Energy Network.

The United States Environmental Protection Agency. (2016). Geothermal Energy.

The USGS Water Science School. (2016). Hydroelectric power: How it works. Retrieved July 17, 2016, from http://water.usgs.gov/edu/hyhowworks.html

The World Bank. (2012). *Geothermal handbook: Planning and Financing Power Generation*.

Thordarson, S. (2008). Hundred years of space heating with geothermal energy in Iceland.

Tilmant, A; Macian-Sorribes, H, P.-V. (2015). Definition of efficient scarcity-based water pricing policies through, 3925–3935. http://doi.org/10.5194/hess-19-3925-2015

Turvey, R. (2006). Interconnector Economics: Electricity. Retrieved February 25, 2015, from http://www.bath.ac.uk/management/cri/pubpdf/turvey/Interconnectors

U.S. Army Engineer Institute for Water Resources. (2009). Hydropower - Value to the Nation.

Union of Concerned Scientists. (2014). How Geothermal Energy Works.

United Nations. (2015). UN Climate Change NEWSROOM.

Valeri, L. M. (2009). Welfare and competition effects of electricity interconnection between Ireland and Great Britain $. *Energy Policy*, *37*(11), 4679–4688. http://doi.org/10.1016/j.enpol.2009.06.020

Viðskiptablaðið. (2013). Viðskiptablaðið - Sæstrengur gæti hækkað raforkuverð meira hér en í Noregi. Retrieved February 25, 2015, from http://www.vidskiptabladid.is/frettir/81385/?q=Raforkuver%C3%B0

Vistica, M. (2012). *Value of Stochasticity in Hydropower Planning Optimization*. EEH – Power systems laboratory Swiss Federal Institute of Technology (ETH) Zürich.

Wellman, M. P., Greenwald, A., & Stone, P. (2007). *Autonomous Bidding Agents: Strategies and Lessons from the Trading Agent Competition*. MIT Press, 2007.

Wilson, A. (2014). Economically Rational Trading Between the All Island Single Electricity Market and Great Britain; Theory Vs Practice, (September).

Wisconsin Valley Improvement Company. (2016). How Hydropower Works.

Zerrahn, A., & Huppmann, D. (2014). Network Expansion to Mitigate Market Power: How Increased Integration Fosters Welfare, 1–25. http://doi.org/10.2139/ssrn.2435896

Appendix A

```
#==============================================================================
 ==  HYDRO_DAY                                                              ==
 ==     Stochastic Dynamic Programming model of reservoir management       ==
 ==     Models single auction for multiple time periods (day-ahead like)    ==
 ==     Iceland: stochastic net inflow, buy/sell from UK                   ==
 ==                                                                        ==
 ==     Olvar Bergland, may 2016   initial julia  version                  ==
 ==============================================================================#
# load additional packages
using DataFrames
####################################################################
#  prepare output file, and say hello                            ##
####################################################################

out = open("hydro_day.txt","w");

println(out,"+----------------------------------------------------------+");
println(out,"| HYDRO_DAY: Charging/Discharging Electric Storage Unit     |");
println(out,"|            Stochastic Dynamic Programming Model          |");
println(out,"+----------------------------------------------------------+");
println(out);
################################################################
# data section                                                 #
################################################################
# read data from external file
data = readtable("../data/spot_no1.csv");
# pull out relevant price variable
p = convert(Array,data[:_price_]);
n = length(p);          # size
# price range
pdlt =   1.00;  # bid increments (coarse for testing)
pmin =   0.00;  # minimum price
pmax = 125.00;  # maximum price
for i=1:n          # loop over prices
   if p[i] < 0.01  # ensure min observed price > 0
      p[i] = 0.01;
   end
   if p[i] > pmax-0.01  # squash top tail
      p[i] = pmax-0.01;
   end
end
sort!(p);               # ascending order

################################################################
# empirical distribution function                              #
#   z[.,1] - p           price                                 #
#   z[.,2] - F(p)        empirical distribution function       #
#   z[.,3] - 1-F(p)      empirical distribution function       #
#   z[.,4] - E(P,P<=p)   average below p  E(P|P<=p)*Pr(P<=p)   #
#   z[.,5] - E(P,P>=p)   average above p  E(P|P>=p)*Pr(P>=p)   #
################################################################
np = round(Int16,pmax/pdlt) + 1;  # price range (0.00-250.00)
z = zeros(np,5);        # holds edf
m = 0;                  # median index
x = 0.0;                # average
q = pmin;               # current price
j = 1;                  # keep track of observed price
for i=1:np              # loop over price range
   k = 0;               # how many obs at this price
   while ((j<=n) && (p[j]<=q))
      k += 1;
      j += 1;
   end
   d = (j-1)/n;         # cumulative density
   y = q*(k/n);         # average at this price
   x += y;              # cumulative average
   z[i,1] = q;          # current price
   z[i,2] = d;          # cumulative density
```

```
   z[i,3] = 1 - d;      # cumulative density
   z[i,4] = x;          # cumulative average
   q += pdlt;
   if d < 0.5
      m = i;
   end
end
# average price
pavg = z[np,4];
# median price
pmed = (z[m,1]+z[m+1,1])/2;
# cumulative average from top
for i=np:-1:1
   z[i,5] = pavg - z[i,4];
end
######################################################################
#  model parameter section                                          ##
######################################################################
# model parameters
r = 0.02;          # discount rate
ß = 1/(1+r);       # discount factor
l_in  = 0.1;       # energy loss in
l_out = 0.1;       # energy loss out
# need a penalty when storage is out-off bounds
ŋ_b =  5*pavg;     # penalty for buying, no storage
ŋ_s = 25*pavg;     # penalty for selling, no delivery
amax =  np;        # number of actions
smax =  49;        # number of states
tmax =   6;        # number of bidding periods
# control parameters
imax =   75;
tol  = 0.001;
#
# print model information
@printf(out,"Number of actions    %9.0f\n",amax*(amax-1)/2);
@printf(out,"Number searched      %9.0f\n",(np-1)*(np-2)/2);
@printf(out,"Number of states     %9.0f\n",smax);
@printf(out,"Number of periods    %9.0f\n",tmax);
@printf(out,"Average market price %9.2f\n",pavg);
@printf(out,"Median  market price %9.2f\n",pmed);
println(out);
######################################################################
#  hydro power production (stochastic)                              ##
######################################################################
fmax = 7;                    # number of outcomes
flow = zeros(Int16,fmax,1);  # net inflow
fprb = zeros(fmax,1);        # probability of flow
# hard code the stochastic production
for f=1:fmax
  flow[f] = f - 4;
end
# symmetric E(flow)=0
fprb[1] =  0.05;
fprb[2] =  0.10;
fprb[3] =  0.20;
fprb[4] =  0.30;
fprb[5] =  0.20;
fprb[6] =  0.10;
fprb[7] =  0.05;
# skewed E(flow)>0
fprb[1] =  0.01;
fprb[2] =  0.04;
fprb[3] =  0.10;
fprb[4] =  0.25;
fprb[5] =  0.35;
fprb[6] =  0.20;
fprb[7] =  0.05;
######################################################################
#  solve SDP model with value function iteration                    ##
######################################################################
v = zeros(smax,1);      # initial values for value function
w = zeros(smax,1);      # holds previous value of value function
r = zeros(smax,1);      # holds previous value of value function
a = ones(Int16,smax,2); # optimal action pointers:
                             # a[s,1] - buy price
                             # a[s,2] - sell price
#a[1,2] = np;
```

```
# adjust unit price to reflect charging/discharging losses
epb = zeros(np,1);      # expected buy price
eps = zeros(np,1);      # expected sell price
for i=1:np
   epb[i] = z[i,4]*(1 + l_in);
   eps[i] = z[i,5]*(1 - l_out);
end
# set some sensible starting values
#     good starting values essential
#     value function iteration is slooow
# starting values in file?
if isfile("hydro_day.csv")
   # read data from external file
   svf = readtable("hydro_day.csv");
   # pull out relevant price variable
   v = convert(Array,svf[:vfunc]);
else
   # ok guess
   v[1] = 3100.0;
   x = 46.0;
   for s=2:smax
      x *= ß;
      v[s] = v[s-1] + x;
   end
end
#
#v = zeros(smax,1);
q = zeros(smax,np,np);
# iterate over value function
it = 0
while it < imax
   it += 1;
   @printf(out,"Iteration %5.0f\n",it);
   flush(out);
   tic()
   # find expected pay-off for each action (a=(i,j)) and each state (s)
   for i=1:np-1
      p_b = epb[i];
      π_b = z[i,2];
      for j=i+1:np
         #
         p_s = eps[j];
         π_s = z[j,3];
         π_k = 1.0 - π_b - π_s;
         # discounted value from the next period
         # stochastic inflow
         for s=1:smax
            #w[s] = ß*v[s];
            x = 0.0;
            for f=1:fmax
               k = s + flow[f];
               if k < 1
                  # curtailment!
                  # the final term is the penalty
                  x += fprb[f]*(v[1] - 10*ŋ_s*(1-k));
               elseif k > smax
                  # overflowing
                  # the final term is the penalty
                  x += fprb[f]*(v[smax] - ŋ_b*(k-smax));
               else
                  x += fprb[f]*v[k];
               end
            end
            w[s] = ß*x;
         end
         # backtrack the auction results
         for t=1:tmax
            r[1] =  -p_b + π_b*w[2] + (π_k + π_s)*w[1] - ŋ_s*p_s;
            for s=2:smax-1
               r[s] = -p_b + π_b*w[s+1] + π_k*w[s] + p_s + π_s*w[s-1];
            end
            r[smax] = -ŋ_b*π_b  + (π_b + π_k)*w[smax] + p_s + π_s*w[smax-1];
            for s=1:smax
               w[s] = r[s];
            end
         end
         # keep expected value
```

```
         for s=1:smax
            q[s,i,j] = w[s];
         end
      end
   end
   # find optimal action (a) and value (v) for each state (s)
   for s=1:smax
      ai = 0;
      aj = 0;
      af = -10.0;
      for i=1:np-1
         for j=i+1:np
            if q[s,i,j] > af
               af = q[s,i,j];
               ai = i;
               aj = j;
            end
         end
      end
      w[s] = af;
      a[s,1] = ai;
      a[s,2] = aj;
   end
   toc()
   # check for convergence
   d = 0.0;
   for s=1:smax
      d += (v[s] - w[s])*(v[s] - w[s]);
      v[s] = w[s];
   end
   if abs(sqrt(d/smax)/v[1]) < tol
      break
   end
   println(out);
   println(out," State    Value  MargVal     Buy    Sell   P(buy)  P(sell)");
   println(out,"----------------------------------------------------------");
   @printf(out," %5.0f %8.2f %16.2f %7.2f %8.4f
%8.4f\n",0,v[1],z[a[1,1],1],z[a[1,2],1],z[a[1,1],2],z[a[1,2],3]);
   for s=2:smax
      @printf(out," %5.0f %8.2f %8.2f %7.2f %7.2f %8.4f %8.4f\n",s-1,v[s],v[s]-v[s-
1],z[a[s,1],1],z[a[s,2],1],z[a[s,1],2],z[a[s,2],3]);
   end
   println(out,"----------------------------------------------------------");
end
#####################################################################
#  print solution and optimal policy                                #
#####################################################################
if it < imax
   println(out);
   println(out,"Optimal solution found");
   println(out);
   println(out," State    Value  MargVal     Buy    Sell   P(buy)  P(sell)");
   println(out,"----------------------------------------------------------");
   @printf(out," %5.0f %8.2f %16.2f %7.2f %8.4f
%8.4f\n",0,v[1],z[a[1,1],1],z[a[1,2],1],z[a[1,1],2],z[a[1,2],3]);
   for s=2:smax
      @printf(out," %5.0f %8.2f %8.2f %7.2f %7.2f %8.4f %8.4f\n",s-1,v[s],v[s]-v[s-
1],z[a[s,1],1],z[a[s,2],1],z[a[s,1],2],z[a[s,2],3]);
   end
   println(out,"----------------------------------------------------------");
end
#####################################################################
#  save the value function and policy                               #
#####################################################################
ppb = zeros(smax,1);
pps = zeros(smax,1);
for s=1:smax
   ppb[s] = z[a[s,1],1];
   pps[s] = z[a[s,2],1];
end

sdp = DataFrame(
      vfunc  = v[:],
      bprice = ppb[:],
      sprice = pps[:]
      );
writetable("hydro_day.csv",sdp);
close(out);
```

Appendix B

```
#===========================================================================
 ==  HYDRO2_DAY                                                          ==
 ==     Stochastic Dynamic Programming model of reservoir management       ==
 ==     Models single auction for multiple time periods (day-ahead like)    ==
 ==     Iceland: stochastic net inflow, buy/sell from UK                   ==
 ==     Second step: smart limited search                                  ==
 ==                                                                         ==
 ==     Olvar Bergland, may 2016   initial julia  version                  ==
 ===========================================================================#
# load additional packages
using DataFrames
#####################################################################
#  prepare output file, and say hello                             ##
#####################################################################
out = open("hydro2_day.txt","w");
println(out,"+----------------------------------------------------------+");
println(out,"| HYDRO2_DAY: Charging/Discharging Electric Storage Unit    |");
println(out,"|             Stochastic Dynamic Programming Model          |");
println(out,"+----------------------------------------------------------+");
println(out);
#################################################################
# data section                                                  #
#################################################################
# read data from external file
data = readtable("../data/spot_no1.csv");
# pull out relevant price variable
p = convert(Array,data[:_price_]);
n = length(p);          # size
# price range
pdlt =   0.10;  # bid increments (coarse for testing)
pmin =   0.00;  # minimum price
pmax = 125.00;  # maximum price
for i=1:n          # loop over prices
   if p[i] < 0.01  # ensure min observed price > 0
      p[i] = 0.01;
   end
   if p[i] > pmax - 0.01 # squash top tail
      p[i] = pmax - 0.01;
   end
end
sort!(p);               # ascending order
#################################################################
# empirical distribution function                               #
#   z[.,1] - p          price                                   #
#   z[.,2] - F(p)       empirical distribution function         #
#   z[.,3] - 1-F(p)     empirical distribution function         #
#   z[.,4] - E(P,P<=p)   average below p  E(P|P<=p)*Pr(P<=p)    #
#   z[.,5] - E(P,P>=p)   average above p  E(P|P>=p)*Pr(P>=p)    #
#################################################################
np = round(Int16,pmax/pdlt) + 1;  # price range (0.00-250.00)
z = zeros(np,5);        # holds edf
m = 0;                  # median index
x = 0.0;                # average
q = pmin;               # current price
j = 1;                  # keep track of observed price
for i=1:np              # loop over price range
   k = 0;               # how many obs at this price
   while ((j<=n) && (p[j]<=q))
      k += 1;
      j += 1;
   end
   d = (j-1)/n;         # cumulative density
   y = q*(k/n);         # average at this price
   x += y;              # cumulative average
   z[i,1] = q;          # current price
   z[i,2] = d;          # cumulative density
   z[i,3] = 1 - d;      # cumulative density
   z[i,4] = x;          # cumulative average
   q += pdlt;
   if d < 0.5
```

```
      m = i;
   end
end
# average price
pavg = z[np,4];
# median price
pmed = (z[m,1]+z[m+1,1])/2;
# cumulative average from top
for i=np:-1:1
   z[i,5] = pavg - z[i,4];
end
####################################################################
#  model parameter section                                       ##
####################################################################
# model parameters
r = 0.02;          # discount rate
ß = 1/(1+r);       # discount factor
l_in  = 0.1;       # energy loss in
l_out = 0.1;       # energy loss out
# need a penalty when storage is out-off bounds
ŋ_b = 10*pavg;     # penalty for buying, no storage
ŋ_s = 10*pavg;     # penalty for selling, no delivery
amax =  np;        # number of actions
smax =  49;        # number of states
tmax =   6;        # number of bidding periods
# control parameters
imax = 25;
tol  = 0.001;
#
# print model information
@printf(out,"Number of actions    %9.0f\n",amax*(amax-1)/2);
@printf(out,"Number searched      %9.0f\n",(np-1)*np/2);
@printf(out,"Number of states     %9.0f\n",smax);
@printf(out,"Number of periods    %9.0f\n",tmax);
@printf(out,"Average market price %9.2f\n",pavg);
@printf(out,"Median  market price %9.2f\n",pmed);
println(out);
####################################################################
#  hydro power production (stochastic)                           ##
####################################################################
fmax = 7;                    # number of outcomes
flow = zeros(Int16,fmax,1);  # net inflow
fprb = zeros(fmax,1);        # probability of flow
# hard code the stochastic production
for f=1:fmax
  flow[f] = f - 4;
end
# symmetric E(flow)=0
fprb[1] =  0.05;
fprb[2] =  0.10;
fprb[3] =  0.20;
fprb[4] =  0.30;
fprb[5] =  0.20;
fprb[6] =  0.10;
fprb[7] =  0.05;
# skewed E(flow)>0
fprb[1] =  0.01;
fprb[2] =  0.04;
fprb[3] =  0.10;
fprb[4] =  0.25;
fprb[5] =  0.35;
fprb[6] =  0.20;
fprb[7] =  0.05;
####################################################################
#  solve SDP model with value function iteration                 ##
####################################################################
v = zeros(smax,1);      # initial values for value function
w = zeros(smax,1);      # holds previous value of value function
r = zeros(smax,1);      # holds previous value of value function
a = ones(Int16,smax,2); # optimal action pointers:
                             # a[s,1] - buy price
                             # a[s,2] - sell price
#a[1,2] = np;
# adjust unit price to reflect charging/discharging losses
epb = zeros(np,1);      # expected buy price
eps = zeros(np,1);      # expected sell price
for i=1:np
```

```
   epb[i] = z[i,4]*(1 + l_in);
   eps[i] = z[i,5]*(1 - l_out);
end
# set some sensible starting values
#     good starting values essential
#     value function iteration is slooow
# starting values in file?
if isfile("hydro_day.csv")
   # read data from external file
   svf = readtable("hydro_day.csv");
   # pull out value function
   v = convert(Array,svf[:vfunc]);
   # pull out buy and sell prices
   ppb = convert(Array,svf[:bprice]);
   pps = convert(Array,svf[:sprice]);
   # map prices to the price vector
   for s=1:smax
      i = 1;
      # buy price
      while z[i,1] < ppb[s]
         i += 1;
      end
      a[s,1] = i;
      # sell price
      while (i<np) & (z[i,1] < pps[s])
         i += 1;
      end
      a[s,2] = i;
   end
else
   println();
   println("Can't find the file hydro_day.csv. Required!");
   println();
   exit();
end
# iterate over value function
q  = zeros(smax,np,np);  # holds objective function values
bp = falses(np,np);      # candidate buy/sell prices
# iterate over value function
it = 0
while it < imax
   it += 1;
   @printf(out,"Iteration %5.0f\n",it);
   flush(out);
   tic()
   # initalize boolean search matrix
   q  = zeros(smax,np,np);
   bp = falses(np,np);      # candidate buy/sell prices
   for s=1:smax
      i = a[s,1] - 6;
      if i < 0
         i = 0;
      end
      while (i<np-1) & (i < a[s,1]+5)
         i += 1;
         j = a[s,2] - 6;
         if j <= i
            j = i+1;
         end
         while (j<np) & (j < a[s,2]+5)
            j += 1;
            bp[i,j] = true;
         end
      end
   end
   # find expected pay-off for each action (a=(i,j)) and each state (s)
   for i=1:np-1
      for j=i+1:np
         if bp[i,j]
            #
            p_b = epb[i];
            p_s = eps[j];
            π_b = z[i,2];
            π_s = z[j,3];
            π_k = 1.0 - π_b - π_s;
            # discounted value from the next period
            # stochastic inflow
```

```
            for s=1:smax
               #w[s] = ß*v[s];
               x = 0.0;
               for f=1:fmax
                  k = s + flow[f];
                  if k < 1
                     # curtailment!
                     # the final term is the penalty
                     x += fprb[f]*(v[1] - 10*ŋ_s*(1-k));
                  elseif k > smax
                     # overflowing
                     # the final term is the penalty
                     x += fprb[f]*(v[smax] - ŋ_b*(k-smax));
                  else
                     x += fprb[f]*v[k];
                  end
               end
               w[s] = ß*x;
            end
            # backtrack the auction results
            for t=1:tmax
               r[1] =  -p_b + π_b*w[2] + (π_k + π_s)*w[1] - ŋ_s*p_s;
               for s=2:smax-1
                  r[s] = -p_b + π_b*w[s+1] + π_k*w[s] + p_s + π_s*w[s-1];
               end
               r[smax] = -ŋ_b*π_b  + (π_b + π_k)*w[smax] + p_s + π_s*w[smax-1];
               for s=1:smax
                  w[s] = r[s];
               end
            end
            # keep expected value
            for s=1:smax
               q[s,i,j] = w[s];
            end
         end
      end
   end
   # find optimal action (a) and value (v) for each state (s)
   for s=1:smax
      ai = 1;
      aj = np;
      af = 0.0;
      for i=1:np-1
         for j=i+1:np
            if (bp[i,j]) & (q[s,i,j] > af)
               af = q[s,i,j];
               ai = i;
               aj = j;
            end
         end
      end
      w[s] = af;
      a[s,1] = ai;
      a[s,2] = aj;
   end
   toc()
   # check for convergence
   d = 0.0;
   for s=1:smax
      d += (v[s] - w[s])*(v[s] - w[s]);
      v[s] = w[s];
   end
   if abs(sqrt(d/smax)/v[1]) < tol
      break
   end
   println(out);
   println(out," State    Value  MargVal     Buy    Sell   P(buy)  P(sell)");
   println(out,"---------------------------------------------------------");
   @printf(out," %5.0f %8.2f %16.2f %7.2f %8.4f
%8.4f\n",0,v[1],z[a[1,1],1],z[a[1,2],1],z[a[1,1],2],z[a[1,2],3]);
   for s=2:smax
      @printf(out," %5.0f %8.2f %8.2f %7.2f %7.2f %8.4f %8.4f\n",s-1,v[s],v[s]-v[s-
1],z[a[s,1],1],z[a[s,2],1],z[a[s,1],2],z[a[s,2],3]);
   end
   println(out,"---------------------------------------------------------");
end
#####################################################################
```

```
#  print solution and optimal policy                                  #
######################################################################
if it < imax
   println(out);
   println(out,"Optimal solution found");
   println(out);
   println(out," State    Value  MargVal     Buy    Sell   P(buy)  P(sell)");
   println(out,"----------------------------------------------------------");
   @printf(out," %5.0f %8.2f %16.2f %7.2f %8.4f
%8.4f\n",0,v[1],z[a[1,1],1],z[a[1,2],1],z[a[1,1],2],z[a[1,2],3]);
   for s=2:smax
      @printf(out," %5.0f %8.2f %8.2f %7.2f %7.2f %8.4f %8.4f\n",s-1,v[s],v[s]-v[s-
1],z[a[s,1],1],z[a[s,2],1],z[a[s,1],2],z[a[s,2],3]);
   end
   println(out,"----------------------------------------------------------");
end
######################################################################
#  save the value function and policy                                 #
######################################################################
ppb = zeros(smax,1);
pps = zeros(smax,1);
for s=1:smax
   ppb[s] = z[a[s,1],1];
   pps[s] = z[a[s,2],1];
end
sdp = DataFrame(
      vfunc  = v[:],
      bprice = ppb[:],
      sprice = pps[:]
      );
writetable("hydro2_day.csv",sdp);
close(out);
```

Appendix C

```
+----------------------------------------------------------+
| HYDRO2_DAY: Charging/Discharging Electric Storage Unit    |
|            Stochastic Dynamic Programming Model          |
+----------------------------------------------------------+
Number of action       781875
Number searched        781875
Number of states           49
Number of periods           6
Average market price    51.77
Median market price     49.85
 Iteration     1
 Optimal solution found
 State     Value   MargVal    Buy    Sell   P(buy)  P(sell)
------------------------------------------------------------
     0  2977.82            59.50  125.00   0.7774   0.0000
     1  3038.22    60.40   54.50  125.00   0.6481   0.0000
     2  3096.97    58.75   50.50  111.60   0.5204   0.0064
     3  3153.99    57.02   47.50   86.60   0.4164   0.0242
     4  3209.50    55.51   46.50   73.50   0.3795   0.0626
     5  3263.60    54.10   45.40   66.50   0.3390   0.1133
     6  3316.67    53.07   44.80   60.50   0.3170   0.2016
     7  3367.67    51.01   44.10   56.70   0.2949   0.2888
     8  3417.12    49.44   43.40   54.70   0.2716   0.3462
     9  3465.38    48.26   42.50   53.50   0.2446   0.3828
    10  3512.78    47.41   42.10   52.50   0.2334   0.4109
    11  3559.46    46.68   41.50   51.70   0.2165   0.4354
    12  3605.49    46.03   41.00   50.90   0.2007   0.4645
    13  3650.93    45.44   40.50   50.30   0.1873   0.4872
    14  3695.84    44.91   40.10   49.70   0.1785   0.5072
    15  3740.25    44.41   39.70   49.10   0.1685   0.5244
    16  3784.21    43.96   39.30   48.60   0.1580   0.5420
    17  3827.75    43.54   39.00   48.10   0.1499   0.5602
    18  3870.90    43.15   38.70   47.70   0.1408   0.5767
    19  3913.69    42.79   38.30   47.30   0.1318   0.5923
    20  3956.13    42.44   38.00   46.90   0.1244   0.6053
    21  3998.23    42.10   37.80   46.50   0.1198   0.6205
    22  4040.01    41.78   37.50   46.20   0.1137   0.6315
    23  4081.48    41.47   37.20   45.80   0.1090   0.6457
    24  4122.65    41.17   36.90   45.50   0.1032   0.6563
    25  4163.53    40.88   36.70   45.20   0.0997   0.6688
    26  4204.13    40.60   36.40   44.90   0.0943   0.6796
    27  4244.46    40.33   36.20   44.60   0.0905   0.6902
    28  4284.51    40.06   36.00   44.30   0.0870   0.6992
    29  4324.31    39.79   35.70   44.00   0.0809   0.7087
    30  4363.84    39.54   35.50   43.70   0.0779   0.7188
    31  4403.12    39.28   35.30   43.40   0.0739   0.7284
    32  4442.16    39.03   35.00   43.10   0.0691   0.7383
    33  4480.95    38.79   34.80   42.90   0.0662   0.7442
    34  4519.50    38.55   34.60   42.60   0.0632   0.7525
    35  4557.80    38.31   34.40   42.30   0.0600   0.7616
    36  4595.87    38.07   34.20   42.10   0.0571   0.7666
    37  4633.70    37.83   34.00   41.80   0.0536   0.7753
    38  4671.30    37.60   33.70   41.50   0.0495   0.7835
```

39	4708.67	37.36	33.50	41.30	0.0467	0.7898
40	4745.80	37.13	33.30	41.00	0.0449	0.7993
41	4782.70	36.90	33.10	40.80	0.0425	0.8035
42	4819.37	36.67	32.90	40.50	0.0405	0.8127
43	4855.81	36.44	32.70	40.20	0.0384	0.8192
44	4892.01	36.20	32.40	40.00	0.0346	0.8231
45	4927.97	35.96	32.00	39.70	0.0306	0.8315
46	4963.64	35.67	31.10	39.30	0.0243	0.8420
47	4998.77	35.13	27.50	38.50	0.0143	0.8637
48	5033.25	34.48	0.00	38.30	0.0000	0.8682

Norges miljø- og biovitenskapelig universitet
Noregs miljø- og biovitskapelege universitet
Norwegian University of Life Sciences

Postboks 5003
NO-1432 Ås
Norway