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Pump Storage Hydropower for delivering Balancing Power and Ancillary Services

A Case Study of Illvatn Pump Storage Power
Plant

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Abstract

The power markets in Europe are changing rapidly. The drastic shift towards renewable energy and interconnection between power markets has brought with it challenges related to power balance and grid stability. Consumption and generation of electric power needs to be at balance at all times and a secure and reliable power system requires sensitivity to multiple time scales. Increased demand for balancing energy and ancillary services has the potential of making pump storage projects in Norway more profitable.

Hydro Energy is evaluating the potential of building a pump storage power plant in the existing Fortun power system in western Norway. This study aims to quantify the income potential when co-optimizing operation in the wholesale electricity market and balancing markets with three different technical design alternatives offering different degree of operation flexibility. Alternative 1 is based on the license application for the project. The fixed speed pump is a reversible Francis turbine with an installed capacity of 39MW in pumping mode and 48MW in turbine mode. The second alternative, Alternative 2, is similar to Alternative 1 only it is equipped with a variable speed pump. Alternative 3 has increased production and pumping capacity as well as a variable speed pump. Investment cost of the three alternatives range from 610mill NOK to 700 mill NOK. The markets considered are FCR day option, the RK market and the spot market. A price scenario for the spot market, FCR market and the RK market are developed. The price scenario is based on assumptions for future demand of balancing power. Power plant operation strategy is chosen based on the hydrological data and a seasonal pumping cycle is considered the best alternative. Income is estimated in respect to historical prices and scenario prices.

The ongoing changes in the power market would potentially be a “game changer” for profitability of pump storage hydropower in Norway and should be considered for investment decisions. The investment analysis of the three technical alternatives shows that ability to participate in balancing markets has the potential to increase potential income significantly. Only Alternative 2 and 3 are considered economic feasible given that 80-100% of the income potential is obtained. Profitability of the projects increase when income estimation is done based on scenario prices. Based on the assumptions and method of this study Alternative 2 is considered the best alternative for Illvatn pump storage project based on investment analysis.

Sammendrag

Kraftmarkedet i Europa er i endring. Omlegging til fornybare energikilder og sammenkobling av kraftmarkeder har ført til utfordringer knyttet til balanse mellom produksjon og forbruk samt nettstabilitet. Produksjon og forbruk må være i balanse til alle tider og et sikkert kraftmarked må ta hensyn til flere tidsoppløsninger. Økt etterspørsel etter balansekraft og systemtjenester kan ha følger for lønnsomheten for pumpekraft i Norge.

Hydro Energi evaluerer mulighetene for utbygging av pumpekraft i et eksisterende vannkraftsystem i Fortun. Formålet med denne studien er å kvantifisere potensiell inntjening fra balanse markeder og systemtjenester. Tre ulike alternativer til teknisk utforming som medfører varierende grad av operasjonsfleksibilitet er presentert. Alternative 1 er basert på informasjon tilgjengelig i konsesjonssøknaden. For dette alternativet er det valgt en pumpe med konstant turtall og med 48MW installert effekt i turbinmodus og 39MW installert effekt i pumpemodus. Alternativ 2 likner på alternativ 1, men pumpen har variabelt turtall. For Alternativ 3 er vannføringskapasiteten økt. Pumpen i alternativ 3 har variabelt turtall. Investeringskostnad for alternativene varierer fra 610mill NOK til 700mill NOK. Primærtjenester, tertiærtjenester og spot markedet er vurdert i inntjeningsestimeringen. Basert på antakelser om fremtidig etterspørsel etter balansekraft og systemtjenester er det utviklet pris scenarioer for de nevnte markedene. Inntjeningsestimat for de ulike tekniske alternativene er utført både for historiske og scenario priser.

Investeringsanalysen for de tre tekniske alternativene viser at deltakelse i balansemarkeder og markeder for systemtjenester potensielt kan øke inntjeningspotensialet betraktelig. Kun alternativ 2 og 3 er vurdert som økonomisk levedyktig ved antakelse om at 80-100 % av inntjeningspotensialet oppnås. Inntjeningspotensialet for alle alternativene øker ved simulering med scenario priser. Basert på antakelsene og metoden brukt i studien er Alternativ 2 er vurdert som den beste løsningen for Illvatn pumpekraftverk.

Preface

This master thesis is the final work of the master program Civil Engineering with specialization within hydropower at the Department of Hydraulic and Environmental Engineering in the Norwegian University of Science and Technology (NTNU).

I would like to thank my supervisor Ånund Killingtveit at the Department of Hydraulic and Environmental Engineering in the Norwegian University of Science and Technology (NTNU) for comments and suggestions through the semester. Furthermore I would like to thank Hans Simen Fougner at Hydro Energy for good advices and guidance and not at least for providing me with relevant data and information for Illvatn pump storage project.

I have enjoyed working with the thesis as I find the subject highly interesting and relevant. The interdisciplinary of the scope require insight in various disciplines which would have been hard to acquire without guidance. Gerard Doorman from at the Department of Electric Power Engineering has given me insight in markets for balancing power and ancillary services, which I am very grateful for. Finally, I would like to thank Lak Norang for involvement and useful discussions on the subject.

Trondheim10th of June 2015

Your Name

Objectives

Describe potential changes in the Nordic and the European power system.

Describe the main challenges with increased generation from wind and solar for grid stability.

Identify and describe types of balancing markets and ancillary service markets in the Nordic power market and explain how pump storage can contribute in such markets.

Identify technical design of pump storage hydropower for delivering of balancing power and ancillary services.

Evaluate different technical alternatives for design of Illvatn pump storage. Develop a cost estimates and an income estimates.

Identify environmental issues related to pump storage hydropower and the challenges with delivering of balancing power and ancillary services in Illvatn.

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Symbol	Unit	Description
A	m^2	Area
a	m/s	Speed of sound
AS	mill m^3	Mean annual runoff
d	m	Diameter
E	N/m^2	Elasticity Modulus
E_{eqv}	kWh/m^3	Energy equivalent
g	m/s^2	Acceleration of gravity
H	m	Hydraulic Head
i	m^3/s	Computed runoff
k	-	Scaling constant
L	m	Length
Q	m^3/s	Discharge
f	Hz	Frequency
h	mVs	Water pressure
L	m	Length
m	kg	Mass
P	MW	Unit output
R	m	Hydraulic radius
T	s	Time
V	-	Weight factor
v	m/s	Velocity
q	m^3/s	Observed runoff
ρ	kg/m^3	Density
η	-	Efficiency
λ	-	Friction coefficient
M	$s/m^{1/3}$	Manning's number

1 Introduction

This chapter aims to give an introduction of the forthcoming Illvtan pump storage project owned by Hydro Energy.

1.1 Fortun hydropower system

Fortun power plant system consists of 13 reservoirs from small to large ones and three hydropower plants; Fortun/Skagen, Herva and Fivlemyr. Herva is the only pump-storage plant in the system to date. Herva pump-storage is run by seasonal cycle operation because of low degree of flexibility. Manually start up and shut down for operation is necessary.

1.2 Illvatn pump power storage project

Hydro Energy applied for license to build Illvatn pump storage power plant in May 2010. The initial motivation for the project is primarily to decrease water loss during spring flood and to move summer production to winter production by increasing storage capacity. I June 2014 NVE (Norwegian Water Resources and Energy Directorate) sent recommendation to OED for project realization.

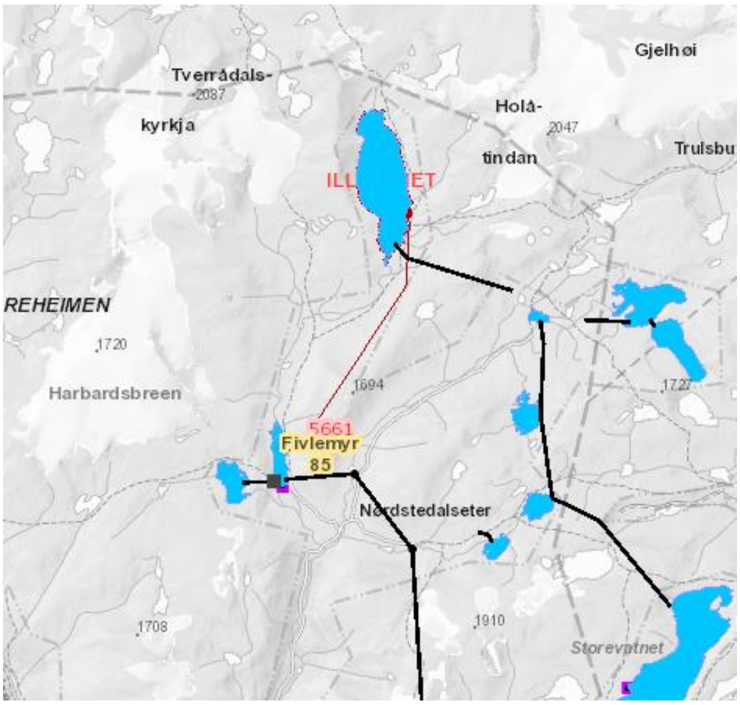

Figure 1 Illvatn pump power project (HydroEnergi, 2010)

Data for the power plant after the upgrading according to license application:

	Illvtan	**Fivlemyr**
Reservoir	140 mill m^3	3,5 mill m^3
Yearly inflow	50 mill m^3	156 mill m^3
LRV	1320 masl	1018 masl
HRV	1382 masl	1028 masl
Regulating meters after upgrading	62 m	10 m
Reservoir area km2	3,86	0,581
Catchment area km2	27,88	54,6

Table 1 Power plant data (HydroEnergi, 2010)

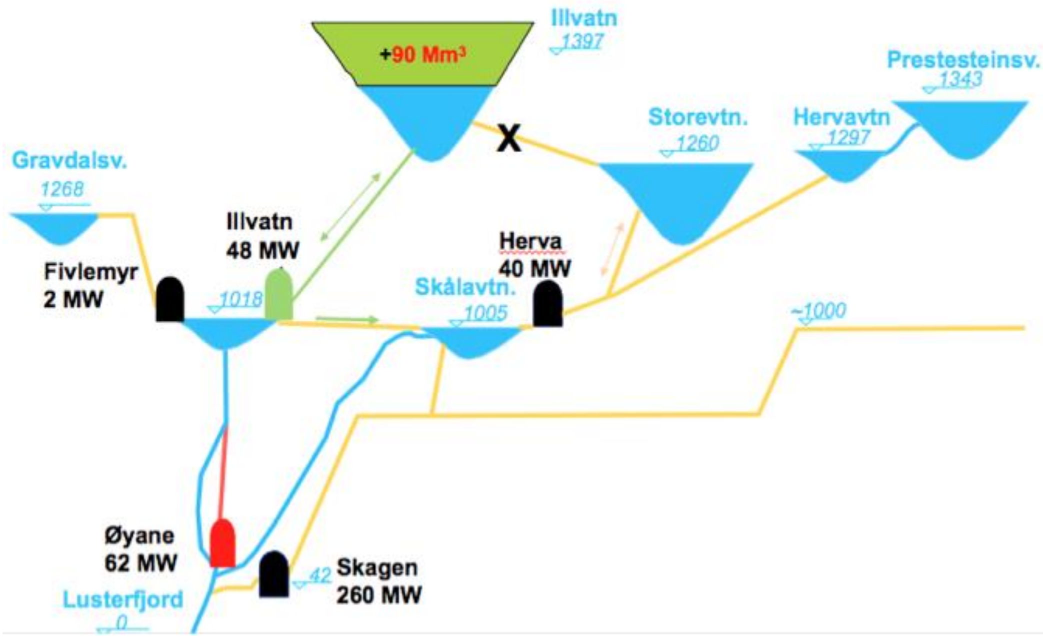

Figure 2 Fortun power plant system

Installed capacity of 48MW in turbine mode and 39MW in pumping mode is evaluated as the optimal solution in the license application. The maximal flow capacity is 15 m^3/sec in production mode and 12m^3/sec in pumping mode. The technical solution includes a fixed speed pump. Increased production in Fortun power system is estimated to be 113 GWh. An investment cost of 445-570 mill NOK is presented in the license application from 2010 (HydroEnergi, 2010). An investment cost of 570mill NOK is used further in this study for the technical alternative presented in the license application.

Impending changes in the power market, such as increased demand for balancing energy and ancillary services, are expected to have impact for profitability of pump storage hydropower in Norway. For that reason, two alternative technical solutions for the pump storage power plant are evaluated in this study. Delivering of balancing energy and ancillary services are possible in pumping mode with an adjustable speed pump but is associated with increased investment cost. Profitability of the technical alternatives considered in this study is evaluated based on income estimations in balancing and ancillary service markets as well as the wholesale electricity market.

1.3 The hydrological foundation

1.3.1 Catchment characteristics and hydrological data

The catchment area for Fortun hydropower station has variation in elevation. The highest elevation is 1800 masl and the lowest point is at 100 masl approximately (Halim, 2007). Annual inflow to Illvatn is about 50mill m^3 and annual inflow to Fivlemyr is 156mill m^3. The area is characterized by a heavy discharge caused by snowmelt in the spring, and low discharge during winter. Precipitation data from 1963 to 2013 is available for analysis. A long time series of hydrologic data is favorable for project evaluation and investment decisions of hydropower.

1.3.2 Scaling from gauging station

Size and elevation is important when scaling hydrological data from another catchment. Small catchments often have small and abrupt peaks compared to large catchments, while elevation of the catchment can affect the timing for snow melt.

In 2007 a hydrological analysis in the Fortun Hydropower System was carried out by (Halim, 2007). The purpose was to develop better hydrological data and to set up a systematic water budget model for all components of the system because of possible upgrading projects. For the operation planning an n.MAG Simulation model was set up. The analysis showed that Gilja gauging station is a good fit to real runoff for most of the Fortun hydropower system and is therefore used as scaling gauging station is this project.

Scaling runoff data using the following methodology and equations carries out calculation of inflow.

$$i_n = \Sigma k_{nj} q_{Gj} \tag{1}$$

Where

i_n computed inflow at selected catchment n

q_{Gj} observed runoff at gauging station (m^3/sec)

k_{nj} scaling constant for catchment from catchment from gauging station determined from catchment area and hydrological condition

$$k_{nj} = V_{nj} \frac{A_n S_n}{A_j S_j} \tag{2}$$

V_{nj} weight factor (here it is assumed as 1)

$A_n S_n$ mean annual runoff at mill m3

n sub catchment no

j gauging station no

Mean annual runoff to Fivlemyr and Illvatn is obtained from pre study reports. The mean annual runoff to Fivlemyr is 156mill m^3 and mean annual runoff at to Illvatn is 50mill m^3. Runoff data for Gilja gauging station is available from 1964 to 2013, mean annual runoff was calculated to be 387 mill m^3.

Scaled daily runoff through the year is visualized in figure 3. The runoff curves are dominated by heavy inflow in the summer months because of snowmelt.

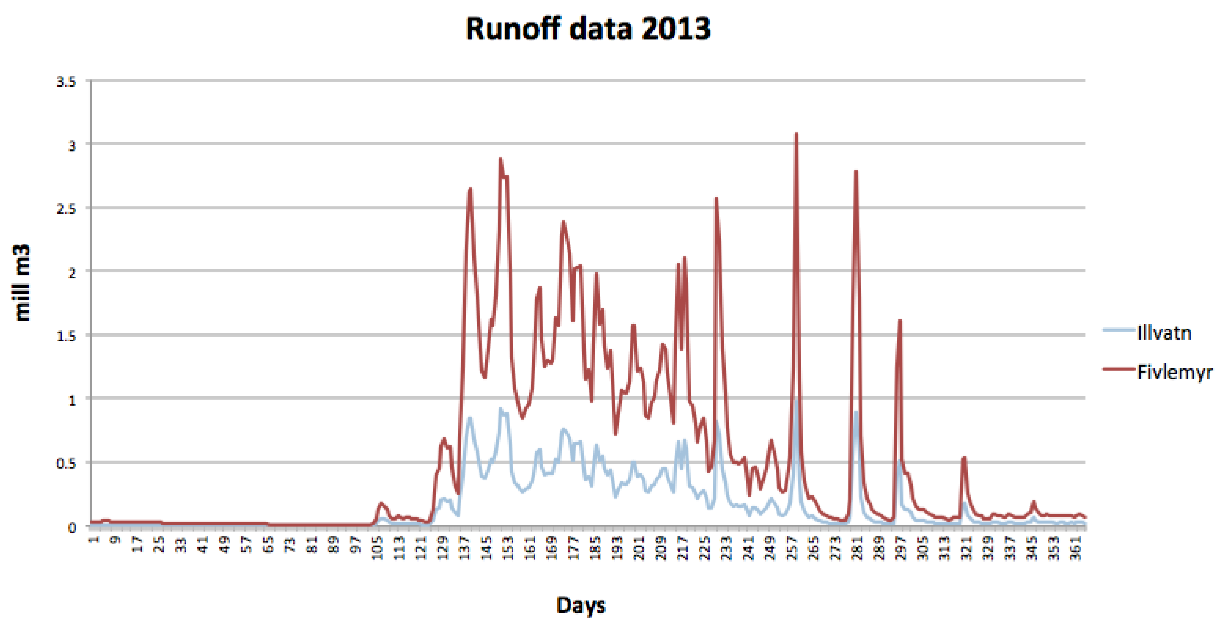

Figure 3 Runoff data 2013

Figure 4 illustrates the variations in runoff from year to year. Runoff data from 2013 are used later in the report for production and income estimation and is therefore marked with a thickened lined in the figure.

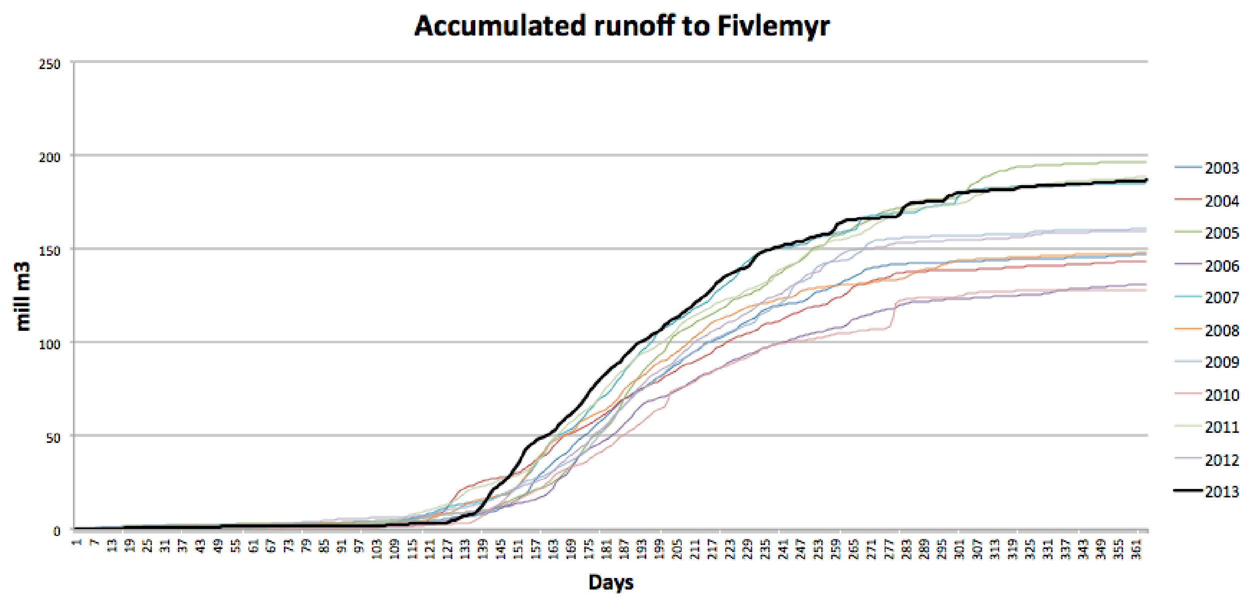

Figure 4 Accumulated runoff to Fivlemyr

1.4 Environmental issues with Illvatn pump storage project

For new hydropower projects and upgrading projects with yearly production above 40 GWh/year an impact assessment for environmental issues is required. Environmental impacts are attached to the construction period and the operation of the pump storage power plant. Negative impacts have consequences for outdoor activity and tourism, cultural heritage, ecological diversity and nature.

The factors expected to influence the environment the most in the construction period are increasing of the reservoir capacity of Illvatn from 50mill m^3 to 140 mill m^3, tunneling of the 7500 meter long waterway and building of a new cable line. However, the conclusion of the environmental assessment report is that this will have limited negative environmental impact because the foundation in Illvatn reservoir is hard rock and erosion will be limited.

For the operation period of the power plant reduced flood during the summer months are expected to have positive impact on agriculture along the waterway. In the recommendation from NVE increased operational regulating of Illvatn reservoir are considered to have negative impact on the environment. Conditions for filling of the reservoir Illvtan during the summer months are suggested, Illvatn reservoir should not be emptied to less than 1 meter below the HRW in the period 1st July to 15th of September.

2 Changes in power generation and the power market

This chapter contains an overview of how changes in the energy market will cause increased demand for balancing energy and storing possibilities in the near future. This is due to increased intermittent energy generation capacity in addition to integration of energy markets which are expected to cause challenges for grid stability and electricity balance. The forthcoming changes in the electricity market evaluated are later used to create price scenarios and to evaluate economic feasibility for pump storage hydropower plants in Norway.

2.1 Norwegian hydropower

Hydropower is the main source of electricity in Norway and Norway holds about 50% of Europe's storage capacity. Figure 5 shows the hydropower potential as of the end of 2012. As illustrated, most of the resources are already developed or protected.

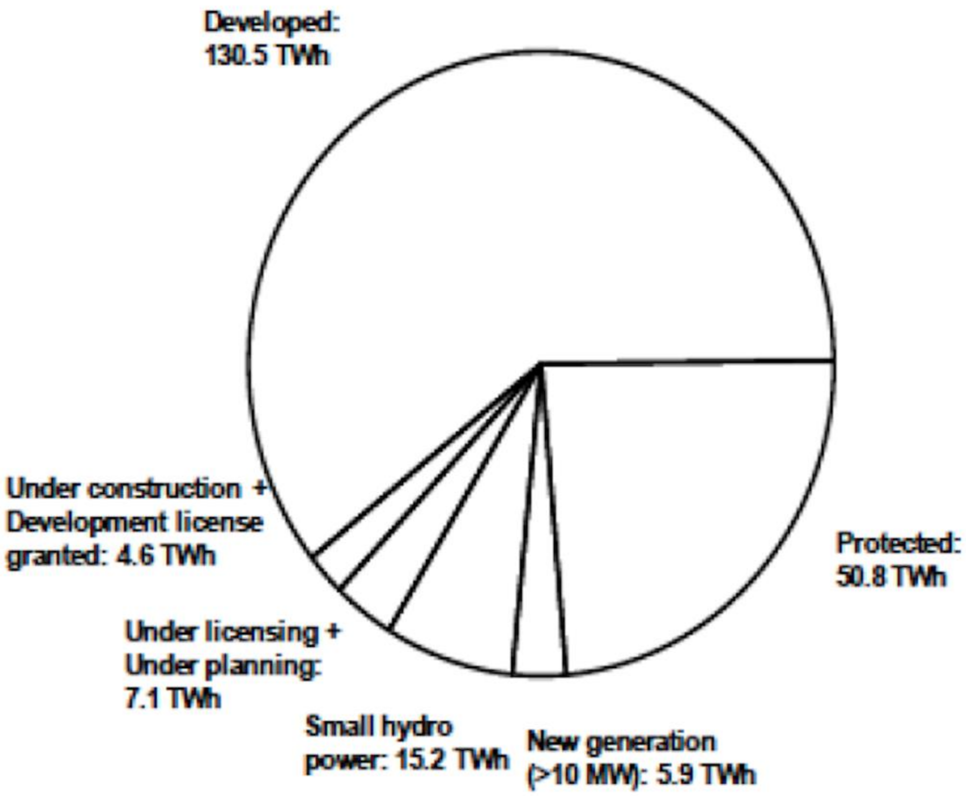

Figure 5 Hydropower resources in Norway (NVE, 2013)

2.2 Changes in generation capacity in Europe

The drastic shift towards renewable energy has led to increase in unregulated power generation. This shift causes challenges for to grid stability and security of supply and therefore increased renewable energy generation requires major changes in the existing operating principle for the electricity market.

EU provides its member states with guidelines and framework for handling challenges related to sustainability and cross-border phenomena. Climate change has been recognized as on such challenge in need to be dealt with. "The Europe 2020 Strategy for smart, sustainable and inclusive growth" includes commitment from the member states to reduce greenhouse gas emission by 20%, increase share of renewables of 20% and achieve 20% energy efficiency by 2020. By 2050, the objective is to reduce greenhouse gas emission by 80-94% compared to the level of 1990 (EU, A Roadmap for moving to a competitive low carbon economy in 2050, 2011). Figure 6 illustrates the pathway towards 80% reduction by 2050.

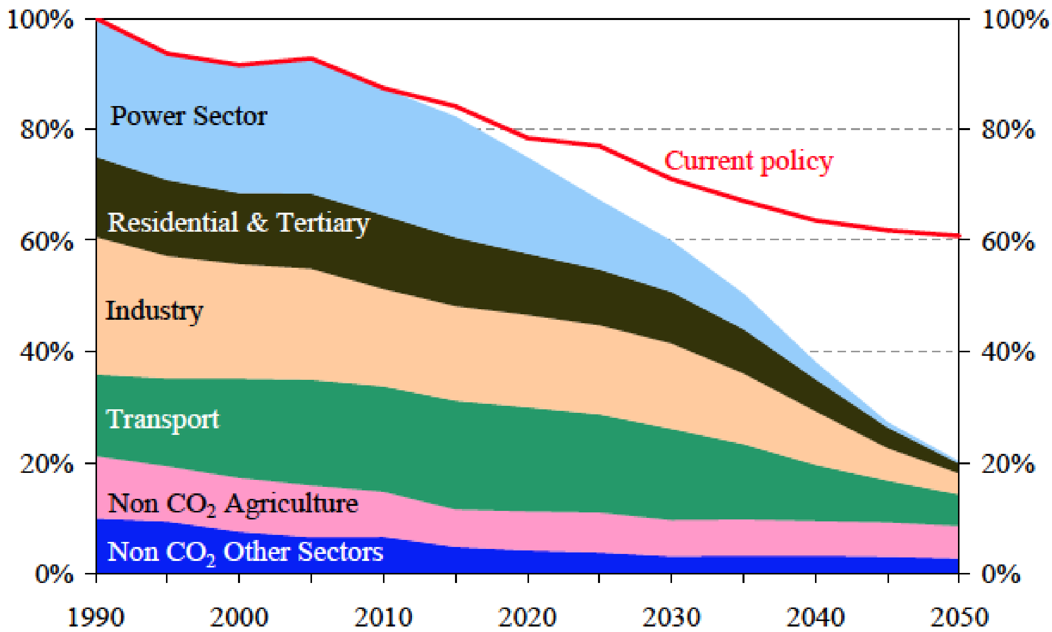

Figure 6 Pathway for emission reduction different sectors (EU, A Roadmap for moving to a competitive low carbon economy in 2050, 2011)

The massive reduction in emission from the power sector implies development of renewable energy generation and reduction of power generation from coal, oil and gas. The annual growth in generation capacity from 2014-2025 is estimated to be 0, 9% (ENTSO-E, Scenario Outlook and Adequacy Forecats 2014-2030 , 2014). According to the International Energy Agency (IEA) the renewable power capacity globally expanded at its fastest rate to date in 2013 (Agency, 2014). In Europe, it is expected a high growth in especially wind and solar photovoltaic (PV). Electricity generation from these sources has varying availability and arise challenges with power balance and grid reliance.

2.2.1 Integration of electricity markets

ENTSO-E, the European Network of Transmission System Operators, represents 41 electricity transmission system operators from 34 countries across Europe. The purpose of ENTSO-E is to promote important aspects and challenges for the European transmission system (ENTSO-E, TSO cooperation and the internal energy market , 2013).

The annual report from 2013 by ENTSO-E states that the creation of the Internal Energy Market (IEM) is central in meeting the European Union's energy policy objectives for affordability, sustainability and security of supply. The IEM is considered crucial in order to meet the decarbonization targets EU has committed to. Integration of electricity markets across borders is supposed to result in a more flexible and efficient use of renewable resources. Figure 7 illustrates how grid development will lead to more efficient use of energy sources for socioeconomic purpose. The fundamental though is that sub-optimization of power generation should be replaced by a unified strategy for resource optimization.

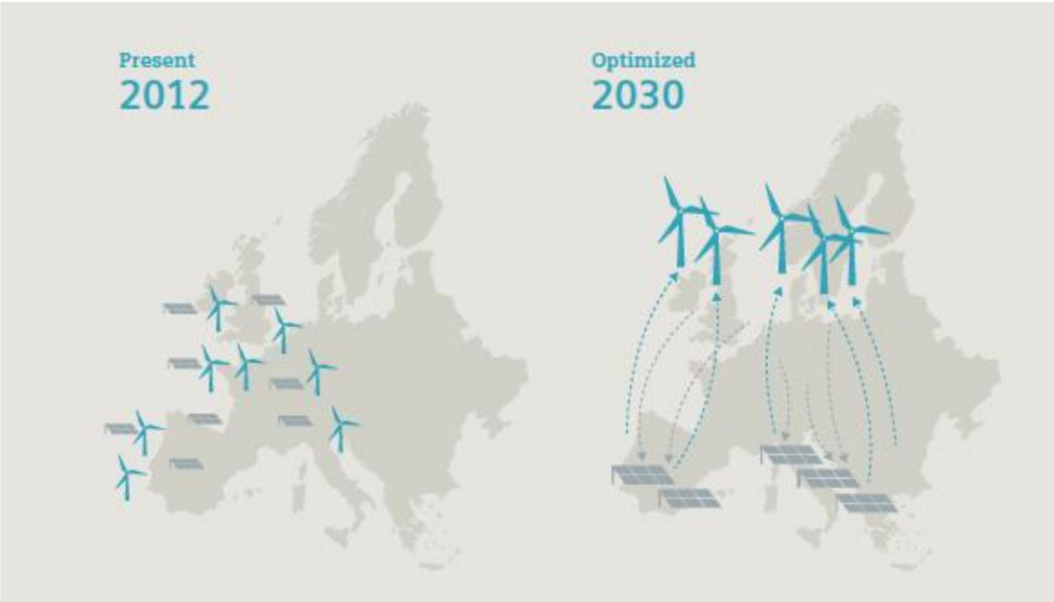

Figure 7 Grid development for efficient utilization of energy sources (Siemens, 2013)

The electricity market integration demands a close cooperation of TSOs to ensure harmonized operational rules and tools. This is coordinated through ENTSO-E. ENTSO-E is mandated by the European Commission to draft the set of rules, the network codes, to facilitate the integration of the European electricity market. The network codes fall into three categories. These are network connection, system operations and electricity markets.

In the spring of 2015, EU launched The European Energy Union to ensure a unified energy policy to meet goals of affordable and climate-friendly energy. One of the specific goals of the framework is that all EU countries should have electricity interconnection representing

10% of the total production capacity (EU, Communitcation from the commision to the European parliament and the council, 2015).

A report from Thema consulting group ordered by NVE evaluates the future of balancing services in the light of the electricity market transition. The report states that cross-zonal capacity can be used for exchange of balancing services in addition to exchange of energy. However, the realization depends on market design. The welfare economic cost of exchange of energy and balancing services are represented by the reduced value of day-ahead exchange. Along with a well-functioning balancing market the cheapest unit for offering balancing power will be utilized first and then in ascending order. The welfare economic benefit is therefore represented by the reduction of the total cost of balancing. Optimal reservation of resources means that the marginal value of exchange of balancing equals the marginal value of exchange of energy in the day-ahead market (Tennebak, Reservation of cross-zonal capacity for balancing services, 2015).

2.2.2 Norway as Europe's "green battery"

Based on Norway's large hydropower potential the idea of Norway as Europe's green battery has been introduced. The idea is that renewable energy from hydropower in Norway will supply Europe with electricity in the hours with limited electricity generation from solar and wind power. In periods with oversupply of generation from wind and solar in Europe, this will provide the pump storage hydropower plants in Norway with cheap electricity. Hence, the pump storage hydropower power plants will perform as a battery. To realize this idea large investment in power networks and transmission cables are necessary.

The joint research center CEDREN (SINTEF, NTNU and NINA) is the initiator to the HydroBalance project which aims to addresses the potential for providing flexibility by the use of Norwegian hydropower. Advantages and drawbacks for Norway of becoming the "green battery" of Europe are evaluated. In the report "Scenarios for large-scale balancing and storage from Norwegian hydropower" four scenarios for the potential future roles of Norwegian hydropower by the year of 2050 are developed. The scenarios differ in degree of integration from Norway with the power markets in Central Europe and the UK, the type of balancing services being exchanged in terms of time horizons and the expected volume of balancing from Norwegian hydropower. The report is aimed towards the decision makers in the power market and gives and overview of potential changes for Norwegian hydropower (Sauterleute, Wolfgang, & Graabak, 2015). A visualization of the scenarios is shown in figure 8.

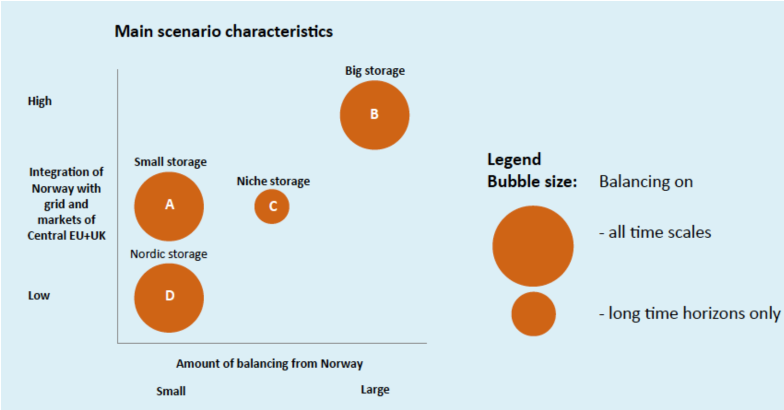

Figure 8 Scenarios for the potential future roles for Norwegian hydropower (Sauterleute, Wolfgang, & Graabak, 2015)

The construction of NordLink, a transmission cable from the south of Norway to Germany was commenced in the spring of 2015. The cable has a planned capacity of 1400MW and should be completed in 2019 and be commercial operating from 2020. A transmission cable connecting Norway and Great Brittan is under construction. The cable has a planned capacity of 1400MW and planned completion in 2021 (Statnett, http://www.statnett.no/Nettutvikling/NORDLINK/).

The interconnection of electricity markets in Europe arise political challenges in addition to technical and economic challenges. Allocation of costs and income from such a project has been debated in the media and triggers many stances. Representatives from energy intensive industry have claimed that the transmission cables from Norway will lead to higher electricity prices, which is negative for the industry in longer terms (Lie). Secondly, nature protecting organizations claim that large-scale expansion of hydropower and transmission cables will cause great damage on unspoilt nature. Gullberg finds in the study “The political feasibility of Norway as the "green battery" of Europe” that Norway might become a green battery in the longer term, but the political feasibility of Norway as a green battery on a short term is unachievable (Gullberg, 2013).

The socioeconomic feasibility of transmission cables is investigated by among others the research center CEDREN and by Tennebak et.al. in the report “Reservation of cross-zonal capacity for balancing services”. A recurring conclusion is that the idea of Norway as a “green battery” for Europe increases socioeconomic revenue because of better utilization of power resources and the possibility of a carbon free power sector. However, in order to attract investors, investment in technological equipment feasible to deliver balancing energy and ancillary services pump storage projects have to be economical feasible for power producers.

2.2.3 Challenges for power balance and grid reliance

There are always imbalances in planned power generation and consumption that needs to be corrected for before real time as generation and consumption of electricity need to be at balances at all times. Reason for discrepancies varies. It can be that demand forecast was not accurate, outages of major components or change in wind/solar generation (Kristiansen, 2007). Another source of imbalance is that generation is usually scheduled for every hour according to the spot market clearing while the load changes continuously.

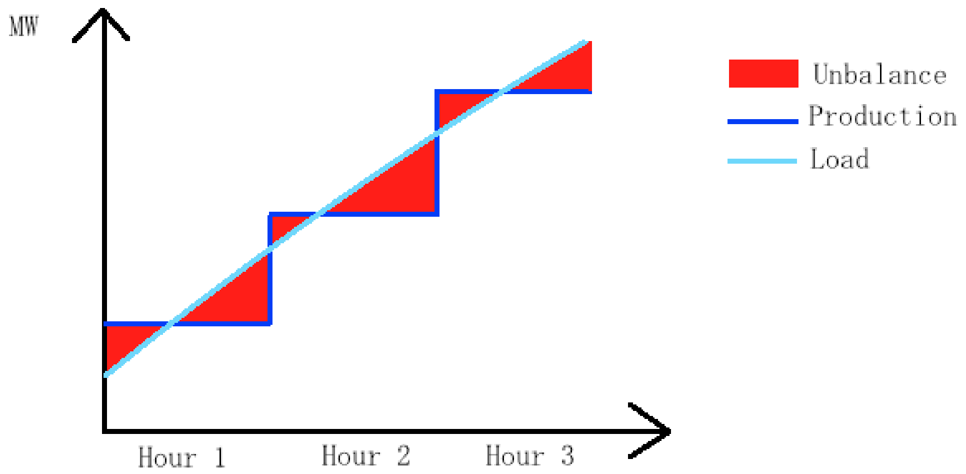

Figure 9 Illustration of imbalance between production and load

Higher amount of non-regulative power generation gives possible greater deviation between expected and actual power generation. Energy storage technologies are crucial when introducing a high share of renewables in the electricity mix to maintain balance between supply and demand. In periods with high wind power production, generation can possibly exceed demand. Available energy storage facilities can then balance the generation output.

A secure and reliable grid system requires sensitivity to multiple time scales (Cochran, 2013). For the power sector in Europe, the massive change in generation capacity implies significantly restructuring in market design and grid development. Development of the grid is necessary to handle transportation of the power to the consumer and to handle the large fluctuations from renewable energy generation. Reduced capability for regulation and more unpredictable power production in Europe will increase the demand and value of flexible power generation that can contribute to rapid up- and down regulations (Statnett, System og marketsutviklingsplan 2014-20, 2014).

Integration of variable renewable energy can affect the market for ancillary services in three ways:

- The variability and uncertainty of wind and solar energy increase requirements for various ancillary services, affecting the scheduling and pricing of those.
- Their impacts vary depending on system conditions, which makes the ancillary service demand difficult to generalize across timescales and systems
- Allowing variable renewable energy to participate in ancillary service markets can offer more supply to the market, but can offer challenges based on the unique characteristics of the variable resources in question.

(Cochran, 2013)

3 The Power Market

This chapter aims to describe the design of the Nordic power market as well as price patterns and typical trends in demand. This background information lays the foundation for power plant operation strategy and for income estimation later in the report. Historical price data are obtained from the web page of NordPool and Statnett.

The Nordic power market was deregulated in early 1990s and this introduced free competition among the power producers. Economic feasibility for the society is the philosophy behind the market structure. A well-functioning power market should correspond well with the physics of the power system. From the market participants' perspective, the power market is a place to make profit by selling and buying power. From the system operators' perspective, the power market is a place for maintaining balance between supply and demand and ensures grid reliance. The marked for balancing power and ancillary services are designed to complement the conventional power sale on the day-ahead market.

3.1 System operator responsibility

The quality of the electricity is collective and therefore cannot be left to the market alone. Statnett, owned by the Ministry of Petroleum and Energy, is the system operator for the Norwegian grid. Solutions and measures implemented by Statnett are based on socioeconomic principles. The main duties associated with the system responsibility are:

- Provide frequency regulating and ensure instantaneous balance of power
- Act impartially and non-discriminating
- Develop market solutions to which leads to an efficient exchange and utilization of the power system
- To the greatest extent as possible apply instruments based on free market principles
- Ensure security of supply and an efficient utilization of the power system
- Prepare and distribute information relevant for the power market as well as conditions of importance for the general security of supply

(Statnett, System og marketsutviklingsplan 2014-20, 2014)

The Nordic countries, except from Jylland, make up a synchronized area. This means that the area has the same grid frequency and imbalances anywhere in the system will affect the rest of the system. Cooperation and coordination of solutions are therefore highly crucial.

Figure 10 The Nordic synchronized area (Statnett, System og marketsutviklingsplan 2014-20, 2014)

Norway and Sweden formed an international power market, NordPool in 1996. The Baltic countries were integrated in the system in the period 2010-13. As a result of this, Norway is integrated in a power market where price signals from other countries are affecting the power price in Norway (Statnett, System og marketsutviklingsplan 2014-20, 2014).

3.2 Different time scales of the power market

The need for balancing and ancillary services differs among countries and greatly depends on the generation mix in the system. The Nordic area has markets for the following products:

- Primary reserves (FCR-N and FCR-D)
- Secondary reserves (FRR-A)
- Tertiary reserves (FRR-M)
- Voltage control

A logical way to divide the power market is the planning phase and the operation phase in real time as illustrated in Figure 11.

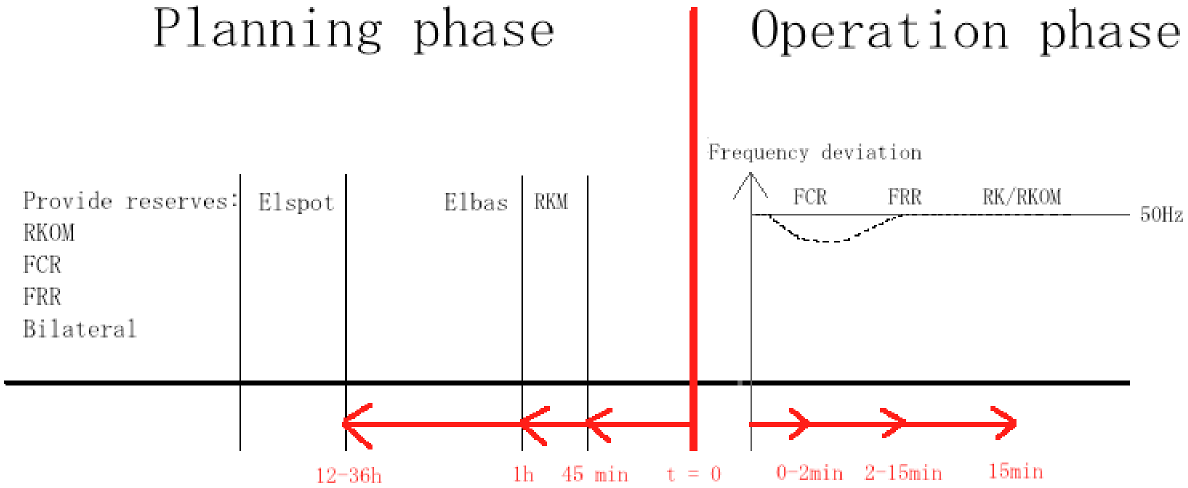

Figure 11 Time-line description the Nordic market

Prior to real time, the participants take positions for the balance and ancillary markets. After closure of the day-ahead market, Statnett is responsible for the power balance and security of supply. Participants must report their willingness to deliver balancing power and ancillary services prior to the operating hour. If needed, Statnett utilizes these reserves. Statnett also has the authority for moving production within quarters in order to adjust imbalances within the hour. This is done manually and Statnett calls the relevant market participants.

3.3 Spot market

The day-ahead marked is the main market for trading power in Norway. The consumer identifies how much power it will need to meet demand, and the producer determines how much power it can deliver to which price. The consumer and the producer announce their bids to NordPool ahead of market closure. Closure time for the day-ahead spot market is 12am. An advanced algorithm at NordPool calculates area prices based on information on supply and demand and not least transmission capacity. Ramping restrictions are implemented in the algorithm because large flow variations over short time may lead to imbalance in the system. For producers planning large shifts in production from one hour to another there is required to present quarterly based production plans.

The Nordic area consists of 12 price areas. Norway is divided into 5 price areas. With no congestions the areas would get the same price.

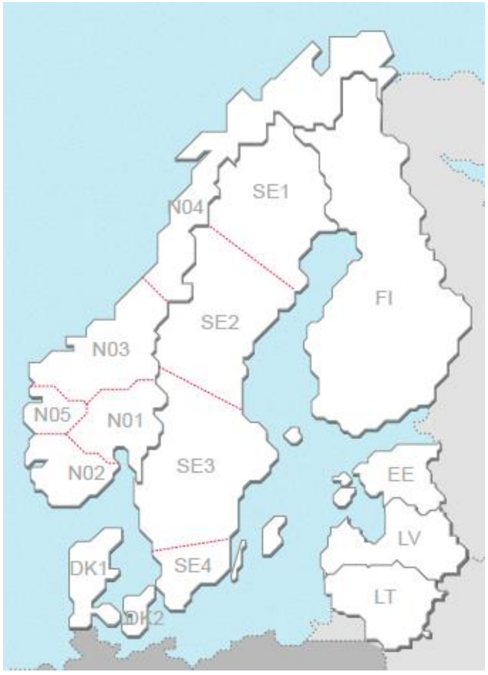

Figure 12 Elspot areas in the Nordic market (Statnett, System og marketsutviklingsplan 2014-20, 2014)

The spot price is a result of bids from the supply and demand side. The hydrological balance is of great importance for the supply side. Low reservoir levels in the winter are bringing prices up. This can be illustrated in Figure 13. The graphs show remarkable increase in price variation in the dry year of 2010. This may be because the price is more sensitive for changes in demand as reservoir have limited water.

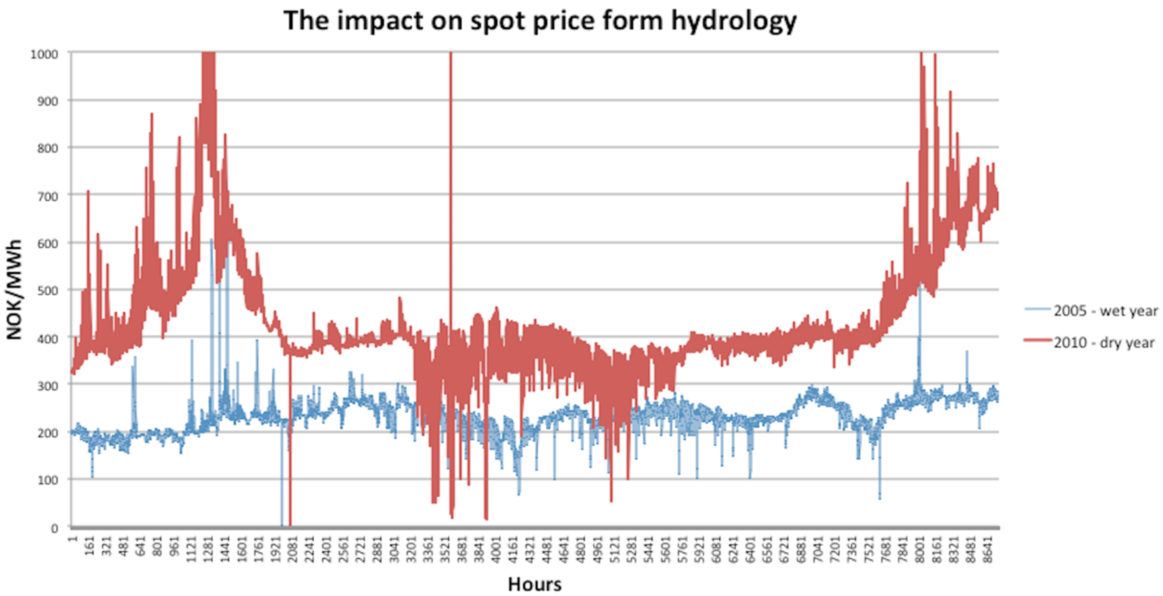

Figure 13 The impact on spot price from hydrology

Demand for power is generally higher in the winter than in the summer. In addition to that production may be limited by dry reservoirs. This leads to high prices during the winter. In the summer, demand is usually low. Because of high inflow to the reservoirs production is high. This leads to low prices during the summer. In times with heavy rainfall or massive inflow to reservoirs caused by snow melting very low prices may occur. Figure 14 illustrates the seasonal variation in spot prices.

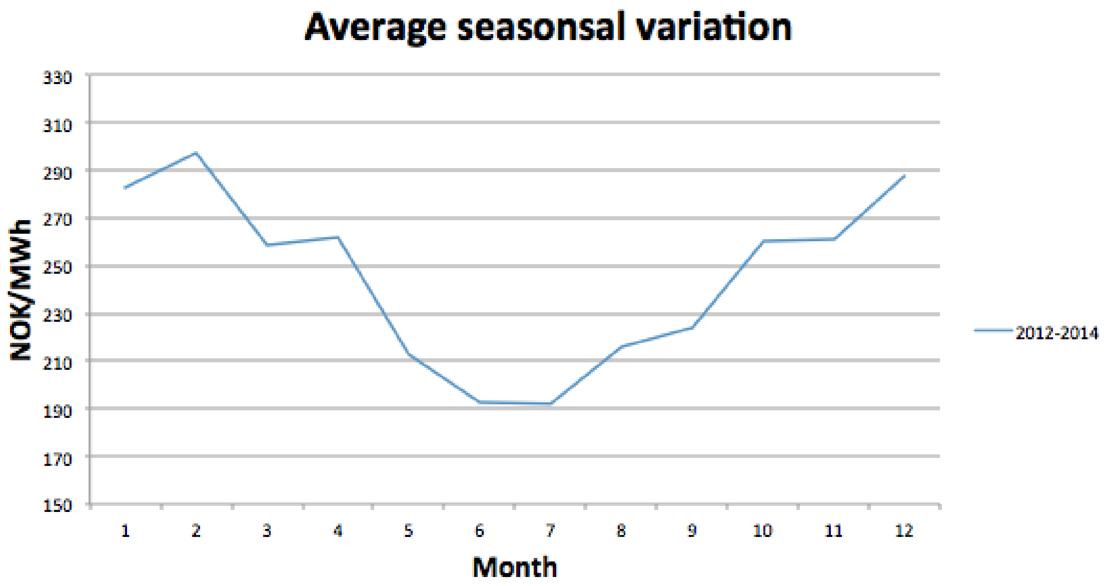

Figure 14 Average seasonal variation

The daily variation in the spot price is affected by the consumption pattern during the day causing low prices in the night and higher prices during the day.

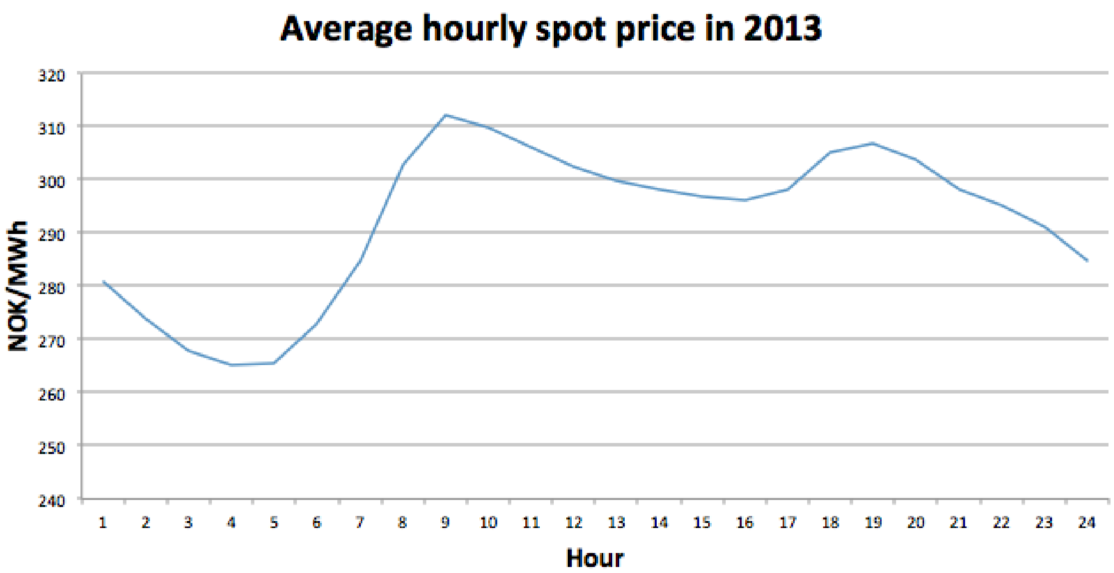

Figure 15 Average daily variation

The variation in power prices in Norway is in general smaller than in other countries. A reason for that is that the energy capacity mainly consists of hydropower that is easy to regulate after demand.

3.3.1 Elbas

Elbas is the intraday market for trading power operated by NordPool. This marked is meant as a supplement to the Elspot market if consumers or producers are not able to satisfy their bids in the day-ahead market. Elbas enables market participants to trade volumes up to real time to bring the market back to balance. Buyer and seller make trades directly with each other via NordPool. The Elbas market for the following day opens at 2pm and market closure is one hour prior to delivery.

3.4 Balancing markets and ancillary services

Balancing refers for the situation after market closure. After market closure the TSO is responsible for the balance between supply and demand and grid stability.

Ancillary services refer to a variety of functions the TSO require to guarantee grid stability and are a crucial part of the balancing (ENTSO-E). Balancing and ancillary services can be provided from supply side or demand side. In a free market the TSO rely on the provision of these service from market participants. Ahead of real time, the TSO ensure to have access to sufficient capacity in their area. This power capacity is often referred to as “reserve energy”. Close to and in real time, capacity may be activated from these reserves and is then referred to as “balancing power” (ENTSO-E, Position paper on cross-border balancing, 2011). Access from a wide range of contributors gives the TSO flexibility to make efficient decisions.

Willingness for providing reserves is based on opportunity cost. Generators will keep capacity available for balancing and ancillary market if profitable compared to the spot market. For some markets the contributor get compensation for reservation of capacity in addition to activation of capacity. By submitting bids in the balancing power and ancillary markets one is obligated to deliver the power if needed and is paid the reservation price. If the system operator demands activation of the reserves to maintain security of supply and grid stability the activation price is paid to the producer. The price for reserves is based on marginal price for the most costly activated bid that hour (Klæboe, 2013). An overview of compensation of the different markets is shown in the Table 2.

Market	Compensation
Spot	Activation
RK	Activation
RKOM	Reservation+ activation
FRR	Reservation+ activation
FCR – N/C week	Reservation
FCR – N/C day	Reservation

Table 2 Compensation of the different markets

3.4.1 Primary reserves, Frequency reserves (FCR)

Frequency control services intend to maintain the system frequency within a given bound of acceptable values. The frequency is modified by continuous control of active power. Unstably of system frequency can lead to machine damage extreme cases blackouts. The reserves are activated automatically and response within seconds to frequency changes.

The unit droop is defined as:

$$s = \frac{\Delta f / f}{\Delta P / P} * 100\% \tag{3}$$

f is frequency and P is unit output.

(Doorman, 2013)

Momentary unbalance is regulated with primary reserves, Frequency Containment Reserves (FCR-N/D). Statnett aims to keep the grid frequency within a narrow bond of 50 Hz (49,9Hz-50,1Hz). In causes with surplus of consumption the frequency drops to under 50Hz and by surplus of generation the frequency increase over 50Hz.

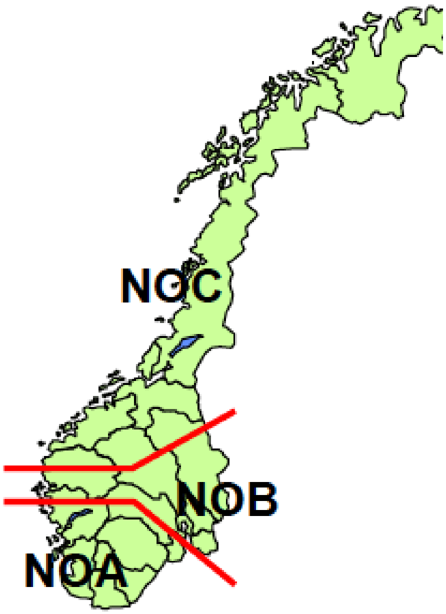

Figure 16 Price areas of FCR market

Primary reserves are automatic activated. This implies that the participant delivering primary reserves must have spinning reserves available, as the unbalance in the frequency must be corrected within seconds. Participants can decide whether they want to participate in the daily market or the weekly market for primary reserves or both. When participating in the option market for primary reserves participants have to allocate capacity in case of activation. For example, if a participant sells 10 MW on a operation unit of 40 MW he can have sell production of maximum 30 MW so that he can increase to 40 MW or reduce to 20MW.

FCR is only paid an option price as it is assumed that over relative short time the net volume turnover would be zero. The Nordic system requirements are 600 MW for FCR-N and 1200 MW for FCR-N.

3.4.1.1 Week market

The week market for primary reserves is divided into weekdays and weekends which again is divided into night (00:00-08:00), day (08:00-20:00) and evening (20:00-24:00). Closure for the marked for weekends are every Thursday at 12:00. Closure for the following week is every Friday 12:00. Approval of bids is provided by 13:00 the same day as bids are sent to Statnett. This means producers are taking positions in the primary reserve week market before the spot market.

The price for primary reserves options is generally high when there are limited spinning reserves. That can be during off peak hours or if the spot price is low. Figure 17 illustrates the option price in the primary reserve week market is shown for each week of 2014. The option price in the week market was significantly higher in the night through the year. Weekend prices are generally higher than weekday prices.

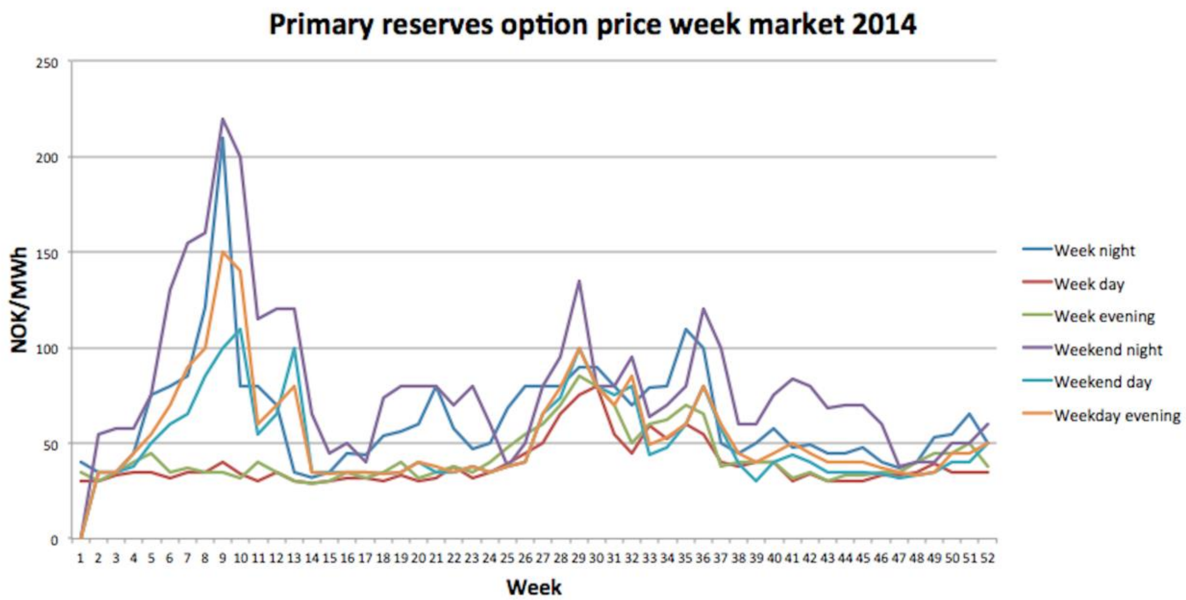

Figure 17 FCR option price week market 2014

Figure 18 illustrates the option price for primary reserves for each week of 2013. The price peak in the summer weeks indicates that the spinning reserves were limited. Similar to the prices in 2014, the night hours had the highest prices during the year.

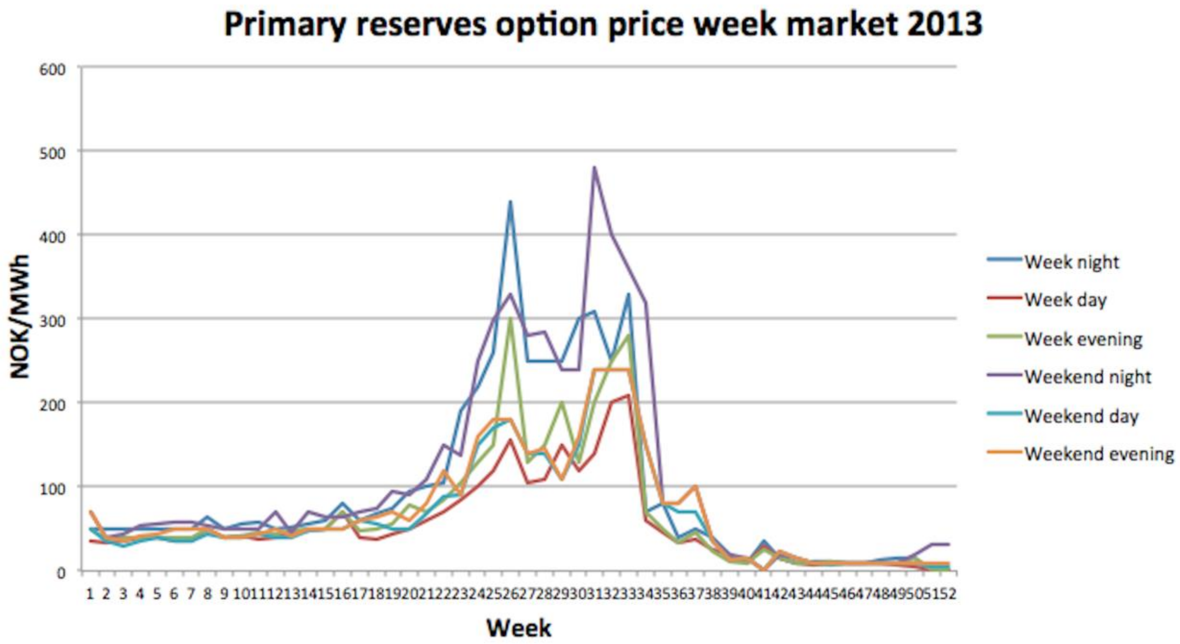

Figure 18 FCR option price week market 2013

Table 3 shows the FCR option price and the turnover volume for 2014 and 2013.

	Week					
	Night		Day		Evening	
	Price	Volume	Price	Volume	Price	Volume
2013	96	13	55	9	69	11
2014	64	20	39	19	43	18

Table 3 FCR option price and turnover volume week 2013, NOK/MWh

	Weekend					
	Night		Day		Evening	
	Price	Volume	Price	Volume	Price	Volume
2013	109	13	67	10	72	11
2014	80	27	50	26	54	26

Table 4 FCR option price and turnover volume weekend 2014, NOK/MWh

Worth noticing is that volume is roughly constant both in weekdays and weekends for both 2013 and 2014. Option price however is higher during the night for weekdays and weekends. This is a consequence of less spinning reserves available during the night than during the day.

3.4.1.2 Day market

The day market for FCR-N options runs every day for every hour with hourly solution. The market closes at 6pm the day before delivery.

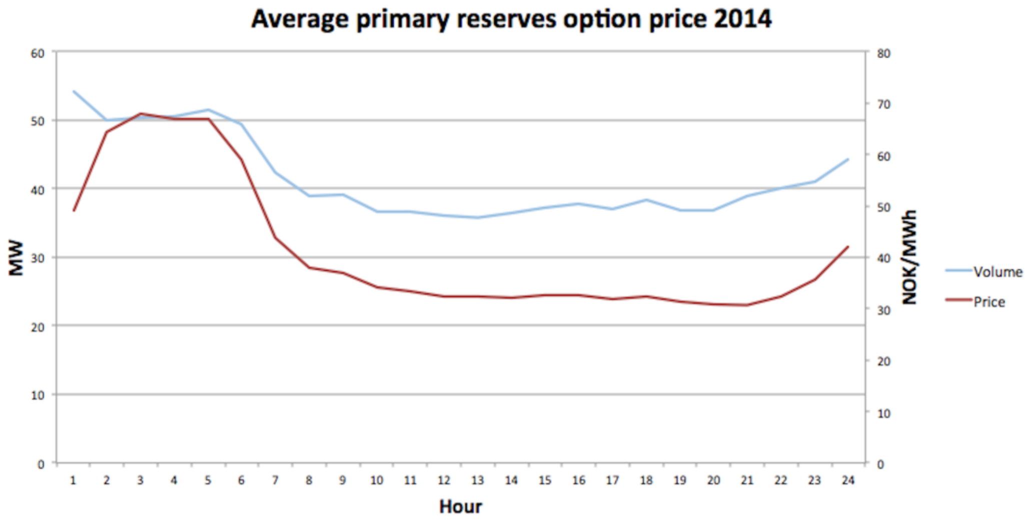

Figure 19 Average primary reservs option price 2014

Figure 18 shows the average primary reserves option price for every hour in 2014 and the average turnover volume. The turnover volume is quite stable over the day with an average of 42 MW per hour. The option price for FCR is significantly higher during the night, between 24pm and 8am. The average option price for FCR is 41 NOK/MWh.

3.4.2 Secondary reserves, Frequency Restoration Reserves (FRR-A)

Secondary reserves, Frequency Restoration Reserves (FRR-A), have the purpose on bringing the frequency back to 50,0 Hz after an unbalance and relieve primary reserves. The response time is 120-210 seconds and the reserve is automatically activated. FRR-A was implemented in 2013 and acquisitions of secondary reserves are currently done on a national basis. The experience with this market has according to Statnett been positive. An important observation is that a volume of 250MW is required for the regulation to have any impact. Efforts are being made to establish a common Nordic market (Statnett, System og marketsutviklingsplan 2014-20, 2014).

3.4.3 Tertiary reserves, Replacement reserves (RKM)

Tertiary reserves are manually operated reserves. The reserves need to be operating within 15 minutes after unbalance. This is equivalent to load following. The bids are activated by a price order; the cheapest units are utilized first. Pump storage plants have a ramp rate capability of 10-30% per minute (Hayes, 2009) and are therefore highly beneficial for delivering of regulating services.

The market for tertiary reserves is split into a market for daily settlement and an option market. The minimum capacity for the day market is 10MW and minimum duration is one hour. The bids should have constant capacity for each hour. Submission of bids leads to obligation for delivering. For the day market closure is 8pm the day before operating hours, but bids can be changed 45 minutes before operation time. The option market is split into a weekly market and a seasonal market. Depending on the power needs to be injected or removed, the system operator demands up or down regulation by calling the market participants.

There has been a common Nordic market for tertiary reserves for the last 10 years, but the countries have their own procedures for securing tertiary capacity in advance. In Norway, reserve capacity is obtained from producers and consumers, while Sweden and Finland utilize their own gas turbines and longtime contracts for this purpose. In Denmark reserve capacity is obtained by contracts for short and long term.

Statnett has invested in a reserve power plant of 300MW. This unit can only be operating in case of a “very urgent power delivery conditions”. This has to be approved by NVE (Norwegian Water resource and Energy Directorate). Sweden has high loads reserves as a backup if there is not sufficient generation during wintertime. It is decided that these reserves should be phased out by 2020 and substituted by market solutions for tertiary regulation.

3.4.4 Voltage control

Voltage control refers to exchange of reactive effect to secure transmission capacity and grid reliance. According to regulations for transmission safety, all production units are obligated to contribute with voltage control within the units’ technical limitations. The producers are paid for required production. The service is activated automatically.

4 Technical design for flexibility

This chapter aims to identify technical design suitable for delivering balancing power and ancillary services. The technical solution of the pump storage plant sets the prerequisites for flexibility operation and for what are the possible products to deliver. With increased need for ancillary services and balance rapid generation variation, there is continuous development in design application areas and control for pump storage hydropower plants. The development of adjustable speed power plants may the most important advances the last decades because it allows for certain extent of controllability in pumping mode (Nysveen, Molinas, & Marta, 2013). The final design is always a compromise between different factors. The final solution is the most economically one as long as it is technical feasible. Also to be considered are reliability, safety, maintenance, operating and replacing costs (Tullis, 1989). In general, more flexible power plant design result in a higher investment cost which must be weighted for the possibility of higher income.

4.1 System dynamics

Flexibility in operation is crucial in order to deliver balancing power and ancillary services. The system dynamics of the pump storage power plant are required to be designed in a way that rapid load changes are possible. Penstock oscillations, pressure in front of the turbine and regulating stability are important issues to identify system dynamics. An overview of hydropower design with respect to system dynamics is done by Nielsen (1990). The following formulas are taken from the report.

Change in flow throughout the turbine will lead to a dynamic change in pressure. The time until a pressure wave is back to valve, response time, is given by:

$$T_r = \frac{2L}{a} \ (s) \tag{4}$$

L is the length of the pipe and a is the sound velocity. The velocity of sound can be found by:

$$a = \sqrt{\frac{\frac{1}{\frac{1}{K} + \frac{d}{TE}}}{\rho}} \ (\frac{m}{s}) \tag{5}$$

K is the water compression module, d is the pipe diameter, T is the pipe thickness and E is the pipe elasticity module. The velocity of sound in water is ~ 1450 m/s and ~ 1200 m/s in tunnels.

When the closing time is smaller than the reflection time, $T_L < T_R$, the change in pressure in front of the turbine is given as:

$$\Delta h = \frac{a * \Delta v}{g} \ (mVs) \tag{6}$$

Δv is the change in flow velocity and g is acceleration of gravity.

If $T_L > T_R$, the change in pressure in front of the turbine is given as:

$$\Delta h = 2 * \frac{\Delta Q}{T_L} \frac{L}{A} \ (mVs) \tag{7}$$

With quick shut down of the power plant the water hammer may lead to severe injury.

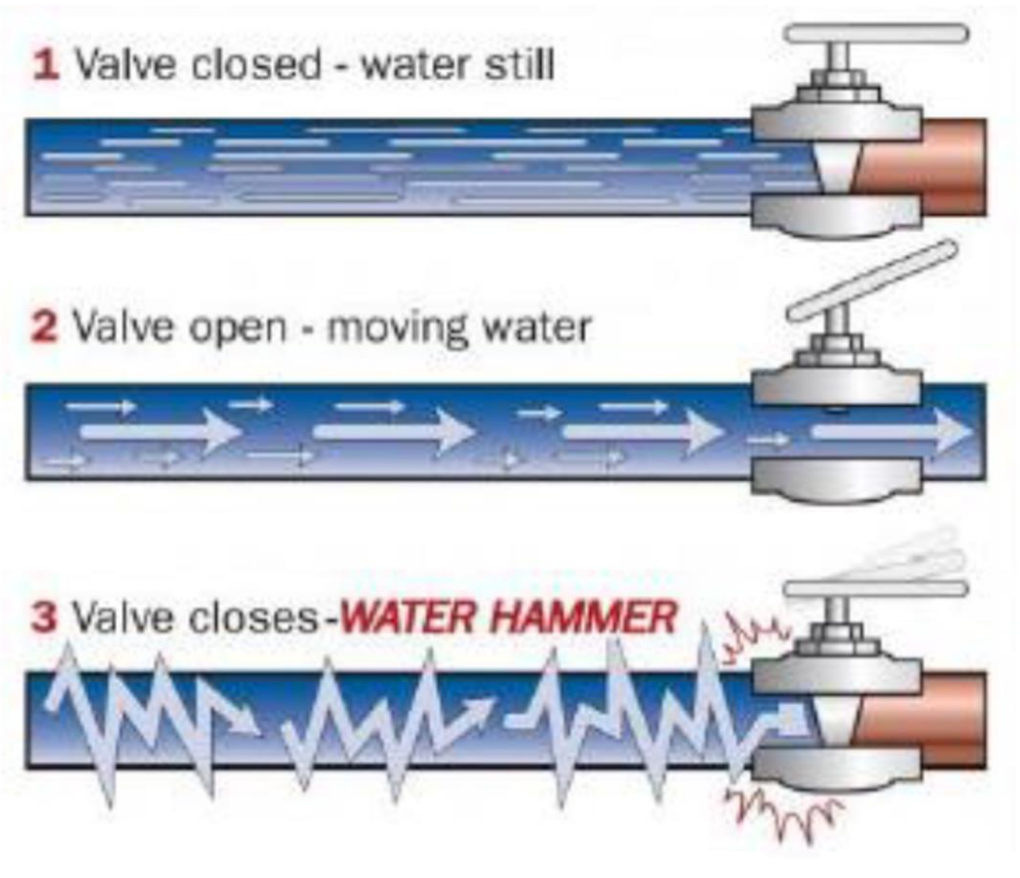

Figure 20 Water hammer illustration (Vereide)

If needed, a surge chamber is applied to improve the system dynamics in the system and to avoid water hammer due to quick load change. The surge chamber design has crucial impact for maintain regulation stability and leads to greater choice for regulation (Vereide). There are various methods in applying surge chamber technology. Air cushion chamber is the most recent surge chamber technology applied in Norway. The air cushion chamber eliminates the need for surface access and the response time of the water mass is improved by placing the air cushion chamber closer to the turbine. This makes rapid load change possible.

4.2 Pump-turbine configurations

4.2.1 Reversible pump turbine

The by far most used solution is the binary set power plant configuration consists of one pump-turbine and one electrical machine (Cavazzini, 2014). Reversible Francis turbine is in most cases used. With this configuration, the power plant can operate only either as a producer or a consumer, which puts limits for the flexibility of operation. On the other side, the configuration usually entails lower investment cost. For pumping mode electrical power is needed. Depending on size of the aggregate and generation technology the system can be operated with fixed or adjustable speed.

4.2.2 Ternary set

The ternary set configuration consists of motor-generator and a separated turbine and pump. Ternary set configurations mostly often used in high head power plants. Because the turbine and the pump are optimized separately one is able to achieve a better efficiency than for a reversible pump-turbine where the mechanical solution is a compromise between pump and turbine mode. Other advantages are simplified start-up in pump mode and shorter start-up time in pump mode (Nysveen, Molinas, & Marta, 2013). Though the configuration has operational advantages, the solution is associated with higher investment costs.

Hydraulic short-circuit is a special configuration of a ternary set solution. With this configuration the pump and the turbine operates simultaneously. This configuration is illustrated in figure 20.

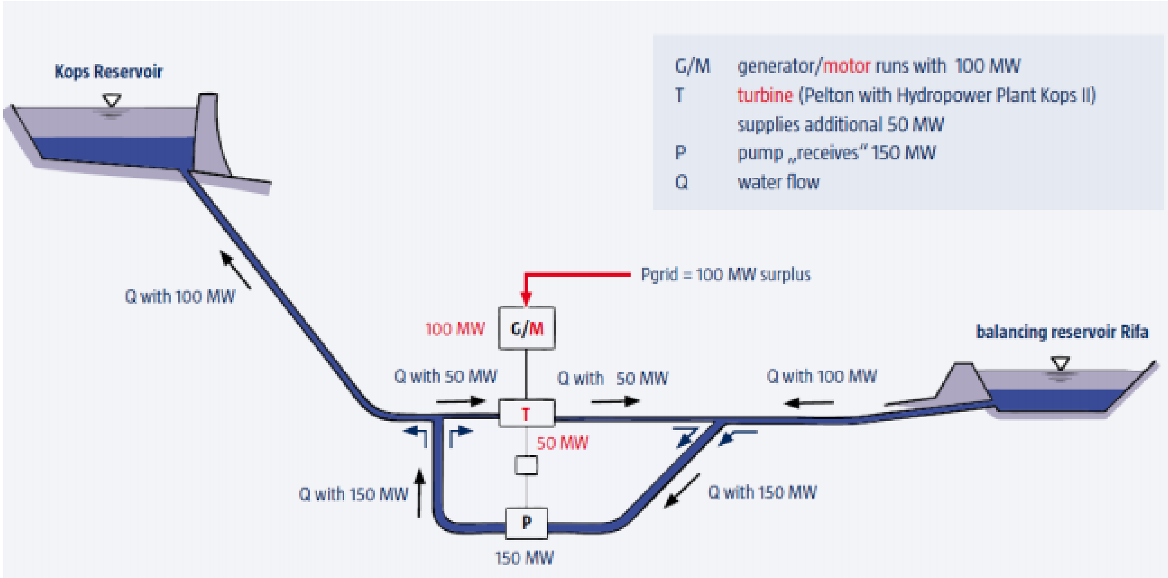

Figure 21 Illustration of a ternary unit configuration with hydrology short-circuit (Cavazzini, 2014)

4.3 Generator/motor configurations

The power systems can be classified into 3 different categories given by the generator and converter technology (Nysveen, Molinas, & Marta, 2013); synchronous machine fixed speed, doubly-fed induction machine adjustable speed and synchronous machine adjustable speed. Synchronous machine at fixed speed is the most used solution today (Nysveen, Molinas, & Marta, 2013). It is the far simplest solution but implies drawbacks in limited controllability. With fixed speed there is only one operating point for a given head in pumping mode.

To improve load balance of production and consumption in the grid, the power plants are required to have a high degree of controllability both in generating and pumping mode. Adjustable speed operation is one of the most important advances of pump storage hydropower the last decades (Nysveen, Molinas, & Marta, 2013) and results in a high degree of controllability. The ability to changing the speed consequently moves the power consumption control from the hydraulic system to the electrical system. As technical development of the required power electronics has moved the equipment into a commercial competitive range, adjustable speed has become more attractive (Koutnik). Nysveen et. al.(2013) sums up the advantages with adjustable speed units compared to fixed speed:

- Increased turn-around efficiency of the pumped-hydro plant
- Load frequency control could be implemented both in pump mode and turbine mode. For fixed speed, load frequency is only possible in turbine mode
- Noise, vibrations and cavitation problems would be reduced due to a greater flexibility in selecting operating strategies when speed as an additional variable
- Greater flexibility in sizing hydro machines for specific sites is available under variable speed operation

- Pumping operation could begin under load at low frequencies eliminating the need for pony starting motors at the same time of allowing to speed up the time for turn-around from turbine to pumping
- Although not a direct benefit from the frequency converter, the plant configurations becomes dual with the frequency converter that could be bypassed anytime and the plant could be operated also in the fixed speed mode.
- Additional support to dynamic stability problems in weak grids (reactive power, active power, voltage and power factor)

Kourtnik emphasizes that the advantage of variable speed power plants are better load efficiency in turbine mode and smoother operation in turbine mode at very low part load in the study “Frades II - variable speed pump storage project and its benefit to the electrical grid”. On the other hand, the civil design of the power house and the cavern has to consider the additional space needed for electrical equipment. This will result in an extra investment cost.

For power stations with more than two pump-turbines, it is not profitable to have more than two of them designed with adjustable speed. The additional units with fixed speed will contribute to an extended operation range for the power system. The fixed speed units will have lower efficiency, but because of high investment cost for adjustable speed it will not be profitable (Hamnaberg, 2011). Figure 22 illustrates how variable speed units better can optimize output to demand.

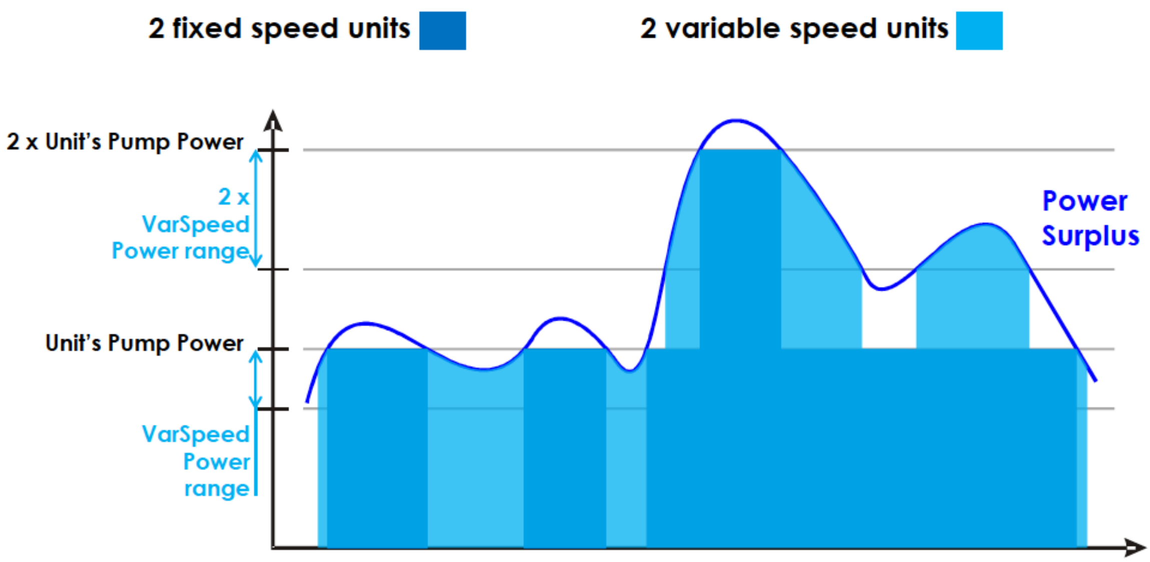

Figure 22 Power range with fixed speed units and variable speed units (Duarte, 2011)

In the following, different solutions in order to obtain adjustable speed pumps are described.

4.3.1 Adjustable speed synchronous machine (SM) with full rated frequency converter

For synchronous machines the electrical frequency produced is synchronous with the mechanical speed of the converter. To obtain adjustable speed with a synchronous machine a full power frequency converter on the stator side used (Cavazzini, 2014). This configuration is only used for power plants smaller than 100MW (Hamnaberg, 2011). A significant drawback with this solution for variable speed is the frequency converter losses, which closely offset the gain for improved turbine efficiency.

Hamnaberg (2011) presents the following pros and cons for synchronous machines with frequency converter:

Advantages	Drawbacks
Flexible operating area in turbine and pump operation	Expensive frequency converter
No need for start-up converter	Generation limit about 100MW
Energy recovery during brakeage for frequency converter	
Synchronous generator has low cost	
Low maintenance requirements for synchronous generator	
Operation direction can change with filled water way	

Table 5 Pros and Cons for synchronized machine with frequency converter

4.3.2 Adjustable speed induction (asynchronous) machine (IM)

For larger power plants variable speed the machinery is linked to the grid with the usage of a doubly fed induction machine (DFIM) (Cavazzini, 2014). The synchronous machine is replaced with an induction machine with wound rotor for this system configuration. The stator is basically equal as for the synchronous machine (Nysveen, Molinas, & Marta, 2013). The configuration for adjustable speed obtained for induction (asynchronous) machines consists of a partially rated frequency converter connected to the rotor side via slip-rings and the stator directly fed to the grid. The use of low-power converter results in less power loss compared to the full rated converter in the asynchronous machine.

This system entails several advantages as controllable reactive power to and from the grid that can be utilized for voltage control in the grid and contribute to stabilization of the power system (Nysveen, Molinas, & Marta, 2013).

Hamnaberg (2011) presents the following pros and cons for doubly fed induction machine:

Advantages	**Drawbacks**
Flexible operating area in turbine and pump mode	More complicated maintenance for asynchronous machines
Possible for generator rating > 100MW	Needs separate rotor transformer and converter
Energy recovery during braking	Asynchronous machines are more expensive
Reactive power control to/from grid	

Table 6 Pros and cons for doubly fed induction machine

Doubly fed machines up to 400MW has been in operating since early 90s in Japan (Nysveen, Molinas, & Marta, 2013).

4.4 Examples of flexible pump storage hydropower worldwide

4.4.1 Frades II – Portugal

The Frades II project is located in the northern region of Portugal. It explodes the hight difference between Venda Nova and Salmonde reservoirs and is a part of the Cavado-Rabagao-Homem cascade system (Voit). Commissioning will happen in 2015 and the machine set delivered by Voit will then be the most powerful of its type.

Portugal relies, to a large extent, on wind, solar and hydropower for electricity. The wind power capacity has increased from around 51 MW to 3700 MW only since 1998. Current plans indicate the capacity expanding to 5400 MW. Because if the increasing part of wind and solar energy capacity, Portugal is in the need of regulating power capacity and energy storage possibilities. Developing of pump storage power plants are in that matter highly beneficial.

The pump storage power plant has a planned capacity of 800 MW, which is about 10% of the overall installed hydropower capacity in Portugal. A variable speed pump with asynchronous motor is chosen which can vary load between 319 MW and 383 MW.

The flexible solution can adjust to the wind power production fluctuations. The ability to stabilize the grid and store surplus electricity is very beneficial. Because of the relatively large size the grid requirements are of special importance.

4.4.2 Worldwide developing of flexible pump storage

Worldwide capacity of variable speed hydropower is expanding as illustrated in the graph below.

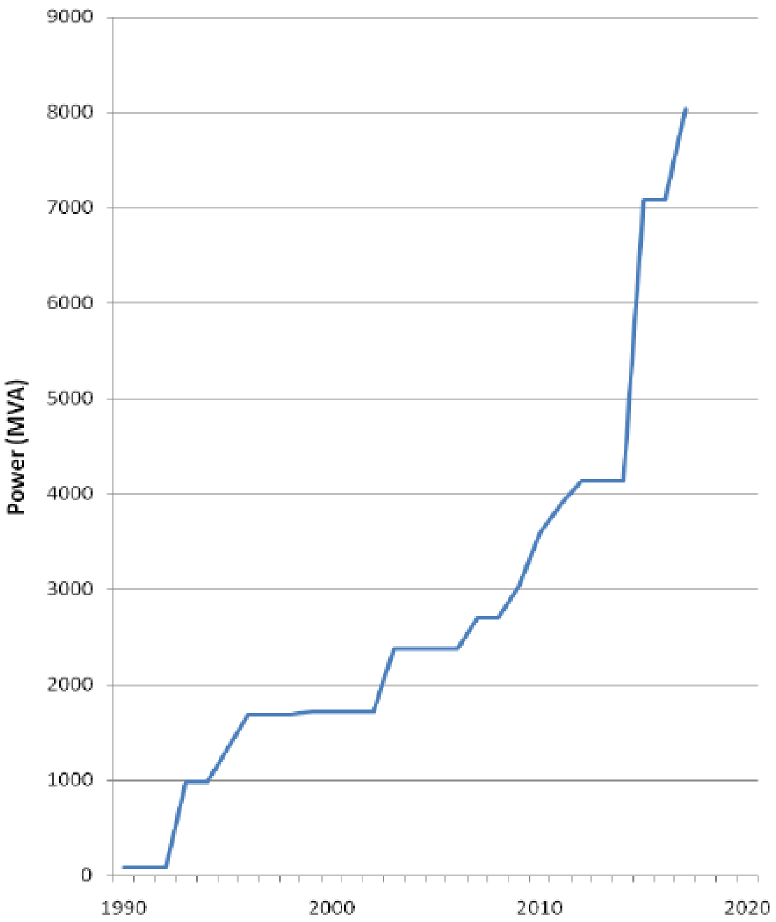

Figure 23 Worldwide capacity of variable speed pumps (Duarte, 2011)

5 General on pump and power plant operation and optimization

This chapter aims to describe how power producers optimize power plant operation based on price forecast, technological design and markets available. As a consequence of deregulation of the energy market plenty of planning tools has been developed in order to serve power producers with the optimal bidding strategy. Hydrology, technological design and market prices set conditions for optimal power plant operation.

5.1 Hydrology and inflow

In cases with heavy rainfall or snow melting the operation are likely to be at full load to avoid water spillage. Opposite, in dry periods, the operation could be completely stopped because of regulations and limits on reservoir volume. Market prices do to a large extent reflect the hydrological balance. This is illustrated in Figure 13.

Pump storage power plants in Norway do mainly serve to increased storing possibilities. In places where storage capacity are limited at the same time as inflow is high, a pump can serve to pump water up at level with better storage possibilities. Pumping operation during periods with heavy rainfall may also be the most profitable as the spot price usually is lower when inflow is high.

5.2 Spot price arbitrage

Spot price arbitrage refers to a strategy with pumping during hours with low prices and production during hours with high prices. The necessary difference in the spot price depends on the efficiency of a pump-production cycle. Figure 24 shows how the optimal number of pumping and production hours is determined by variance in the spot price.

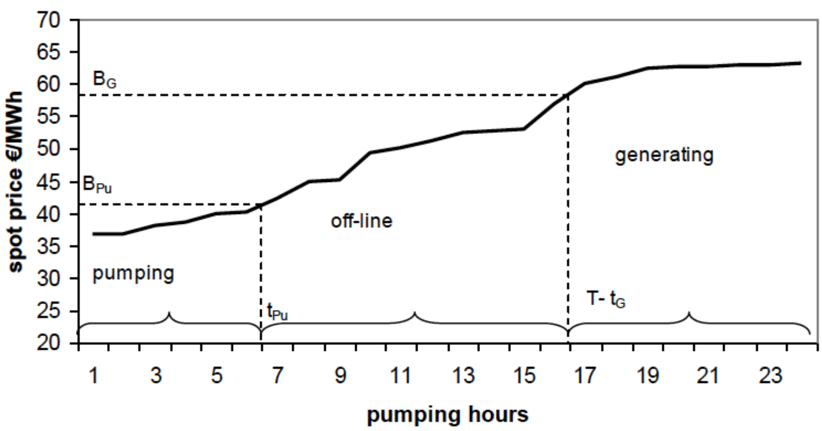

Figure 24 Pumping and generating hours as a function of spot price variation (Wilde)

Figure 25 show the concept of load levelling and peak shaving. As illustrated the demand for energy varies during the day as do the price. The pump storage power plants help smoothening this variation by storing water and consume energy in periods with low demand and low prices. In periods with high demand and high prices energy are produced. By load levelling the purpose is to even out the demand curve for power. Peak shaving exploits the price differences during the day to pump and produce.

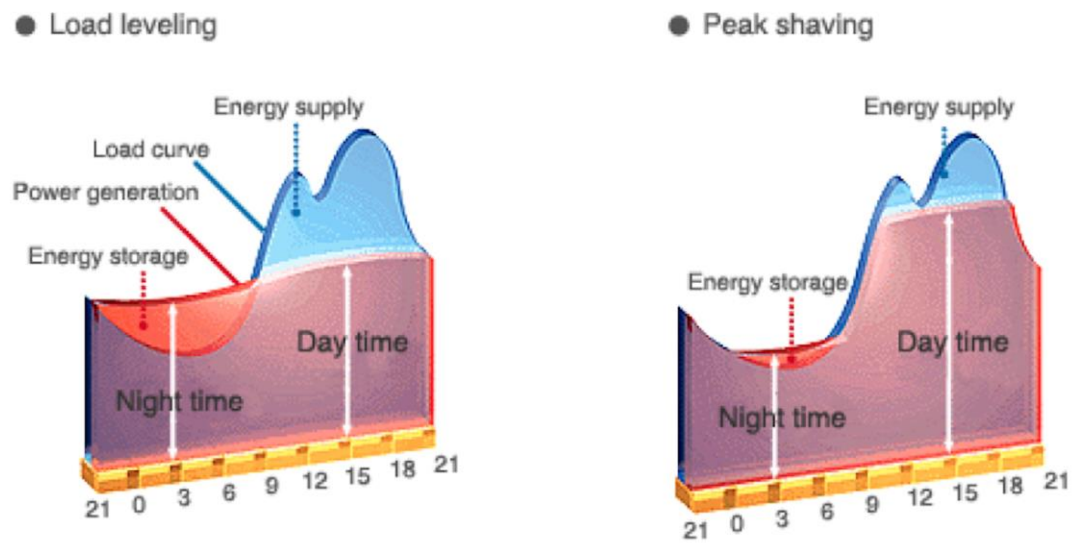

Figure 25 Load levelling and peak shaving (http://actinideage.com/2015/02/01/its-the-economy-storage/)

5.3 Co-optimization in energy markets and ancillary serves

Power producers aim to optimize portfolio profit by pursuing profits in available markets. The study "Operating Hydroelectric Plants and Pumped Storage Units in a Competitive Environment" by Deb concludes that a traditional peak-shaving strategy for pumped storage severely underestimates the financial potential for a pump storage plant because the strategy fails to recognize the profit from ancillary service markets. Different bidding strategies are compared and simulations show that the bidding strategy which are simultaneously bidding in energy and ancillary service markets potentially can double yearly income compared to only bidding in energy markets. Optimization of operation can be done with different time frames for example over a day, a week or year. The chosen strategy for optimization is depended on how price differences occur over the respective time frames.

The mathematical optimization problem of participating in both wholesale electricity markets and balancing and ancillary service market is very complex. In contrast to the spot market, price forecasts for the reserve markets are mostly absent because their market mechanisms are highly complex and difficult to model (Engels, Harasta, Braitsch, Moser, & Schäfer, 2011). To make informed decisions regarding allocation of resources in the spot market and balancing markets producers need good forecast. In the study "Benchmarking time series based forecasting models for electricity balancing market prices" by Klæboe et.al a range of earlier published models for forecasting balancing prices are benchmarked for 1 h-ahead and day-ahead forecast. The models differ in type and explanation factor. For example do some of the models use the day-ahead market price as explanation factor, whereas other finds no correlation. The study concludes that none of the benchmarked models produce informative forecast for balancing prices. This observation is considered as a sign of an effective balancing market as a predictable relation between the information given before closing time and realized prices could open for speculative possibilities.

Revenue possibilities in reserve markets and added income with co-optimizing in wholesale electricity market and reserve markets have been investigated in previous studies. A previous study done by Engels et.al was meant to estimate different alternatives for the Waldeck+ project. The study particularly noted the revenue potential for down regulating during off-peak by operating in pumping mode.

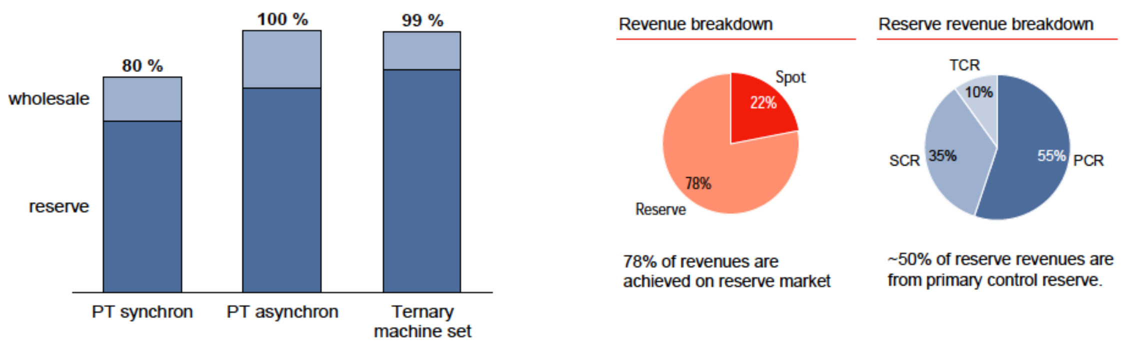

Figure 26 Revenue breakdown for pump-turbine (Engels, Harasta, Braitsch, Moser, & Schäfer, 2011)

Figure 26 shows comparison of achievable contribution margin. The figure to the right shows the revenue breakdown for pump-turbine with asynchronous generator. The simulations are done with actual market prices in 2009 in Germany. Operation plan is optimized for reserve market with the wholesale market as a side product. The study concludes that for the German power market, the largest revenue can be achieved in the reserve markets, irrespective of the type of machine. However, the degree of flexibility of the technical configuration can potentially lead to significant gains in contribution margin.

5.4 Technical restrictions for participating in balancing and ancillary service markets

The technical configuration of the pump storage hydropower plant defines major flexibility parameters that are relevant to describe ability to participation in different markets. In the following, three alternatives with different degree of flexibility is described.

5.4.1.1 Reversible pump turbine - fixed speed

With a fixed speed pump turbine the flexibility of operation is limited. Load change in turbine mode is possible, though not possible in pump mode. Because of the restrictions on flexibility in pump mode only the spot market is considered for income estimation in pumping mode. In turbine mode the spot market, primary service, secondary service and tertiary service can be considered.

5.4.1.2 Reversible pump turbine - variable speed

The solution of a variable speed pump turbine gives the possibility to change load in pumping mode. This is necessary to be able to deliver primary, secondary and tertiary reserves in pumping mode. The ability of rapid load change is a prerequisite to participate in balancing markets. The ability for regulating load in pumping mode could also show to be economical feasible when pumping over a longer time period. Then the operator can lower the load during the day with normally higher prices and pump on maximum load during the night with low prices. The average pumping price would be significantly lower than just pumping on maximum capacity the whole period.

5.4.1.3 Ternary set – hydraulic short circuit

Ternary set configuration gives the highest degree of flexibility of the three alternatives. Hydraulic design for a reversible pump turbine is challenging and do entail a compromise of necessities. For example, the peripheral speed of the impeller must be commensurate to the lift height in pump mode. Large lifting height consequently makes the diameter of the impeller much bigger than necessary for a turbine. Less pumping capacity compared to turbine capacity is often selected as a compromise. Pump and turbine operation also do have different requirements for machine submerge where the pump require the greatest submerge (Olafsson, 2014). With a ternary unit, separate pump and turbine a better efficiency in both pumping and turbine mode is possible and the ability of rapid load change is also possible. Adjustable speed in pumping mode may lead to higher operating income.

Nicolet sums up the pros and cons related to investment in ternary unit system compared to the reversible fixed speed solution. The increase in civil cost because of increased total shaft length and more expensive electromechanical equipment due to numerous components are the reasons for increased investment cost. Also, the operating and maintenance cost are likely to increase because of the electromechanical complexity and increased number of components (Nicolet).

6 Illvatn power plant operation and income estimation

This chapter aims to quantify the added income after project realization from the available inflow to Fivlemyr and Illvatn. Income estimation is based on both historical prices and a price scenario. Yearly income from the available inflow to Illvatn and Fivlemyr are calculated for three different technical alternatives that offer various degree of operation flexibility. A zero option alternative is also presented in order to compare increased in income from available inflow. All calculations are done in Microsoft Excel.

The main purpose of the pump storage project is to increase production from available inflow to Illvatn and Fivlemyr. Secondly, by increasing storing possibilities one will obtain increased flexibility of operation, meaning production can happen when the prices are high. Investment in a flexible pump turbine system, for example variable speed pump, has the potential to further increase income because of the possibility to participate in balancing market and ancillary service markets in pumping mode.

The calculated incomes are assumed as maximum potential income and it is not realistic than one are able to obtain the estimated incomes. However, it serves to quantify what is possible with a “best case scenario”. The income potential is then reduced to 80% and 60% for a more realistic investment analysis.

6.1 Simulation strategy

6.1.1 Hydrology and its impact on operation

Illvatn and Fivlemyr reservoirs differ greatly when it comes to storing capacity and natural inflow. After project realization Illvatn will have a reservoir capacity of 140 mill m^3 and Fivlemyr will have a capacity of 3,5 mill m^3. Hydrology and inflow to the reservoirs has a great impact on power plant operation. Available water in Fivlemyr reservoirs sets the boundaries for pumping and production possibilities. Figure 27 is graphical illustration of inflow in 2013 and reservoir capacity for Illvatn and Fivlemyr reservoir. The reservoir capacity in Fivlemyr is small compared to the inflow and reservoir capacity in Illvatn is remarkable large compared to the inflow. Pumping from Fivlemyr to Illvatn is therefore necessary in order to exploit the available water recourses.

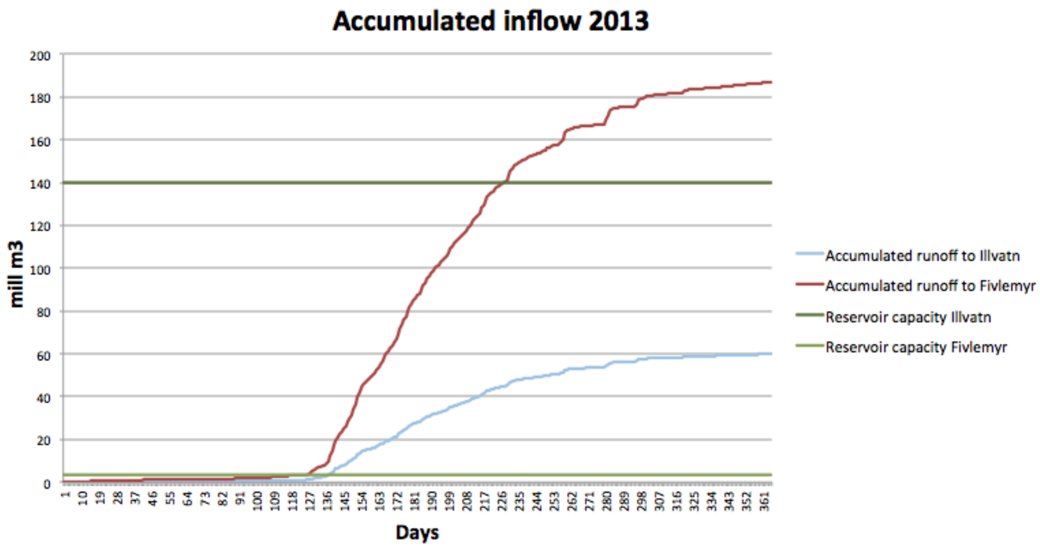

Figure 27 Runoff in 2013 and reservoir

Figure 28 illustrates monthly inflow to Fivlemyr reservoir in 2013. As illustrated, runoff occurs in the summer months, April-October.

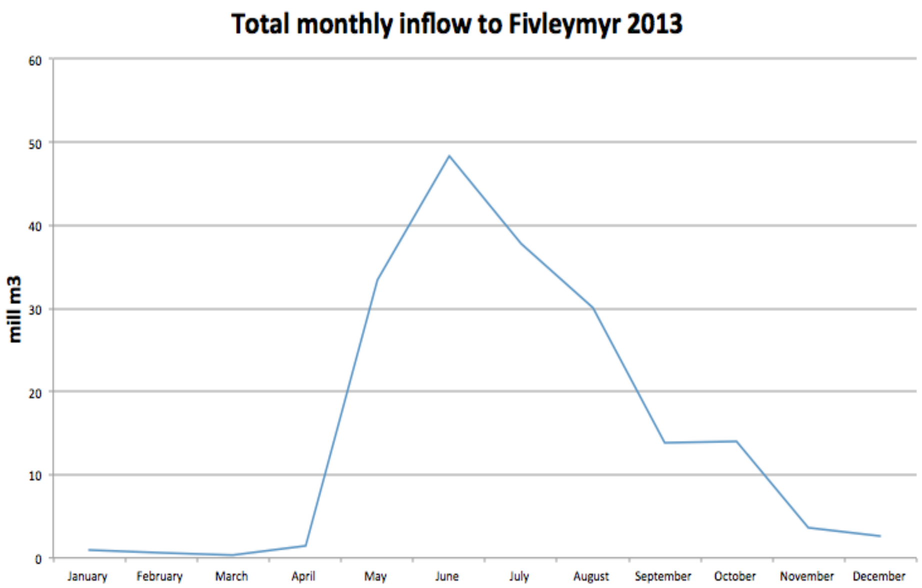

Figure 28 Total monthly inflow to Fivlemyr 2013

6.1.2 Simulation period

The graph below shows the spot price for the period chosen for power plant simulation. The chosen period is from May 2013 to April 2014. The period is chosen based of the pattern of the inflow to the reservoirs in addition to being the period with the newest available data both on hydrology and market prices.

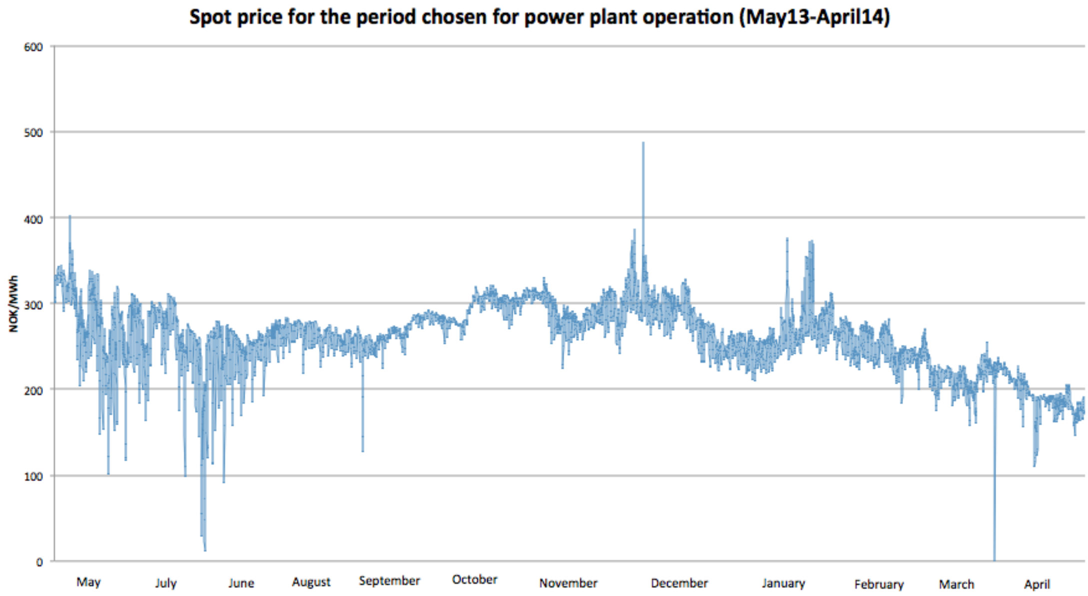

Figure 29 Spot price for the period chosen for power plant operation (May13-April14)

The period of power plant simulation is split in to two periods; the summer period and the winter period. The reason for this is the fundamental differences in inflow to the reservoirs and thus power plant operation possibilities. As discussed, inflow to the reservoirs do primarily occur May-October. This period is therefore referred to the as the "summer-period" and it is the period applicable for pumping. It is assumed that the main objective is to fill up Illvatn reservoir to a maximum in order to maximize total production. This water can also be exploited further down in the system on Skagen power plant. Winter prices tend to be higher than the summer prices as Norwegian spot prices are driven by inflow to the reservoirs. It is therefore assumed that it is always profitable to pump up water to a maximum in the "summer period". This operation strategy corresponds well with the operating restrictions proposed by NVE which includes that production in the period 1st July to 15th of September if water level in Illvatn is below a certain level.

The period November-April is referred to as the "winter-period". For simplification reasons inflow in the winter period is set to zero. The winter period is consequently about trying to optimize available water in the reservoir for production. The "summer period" and the "winter period" are handled as two independent problems.

6.1.3 Simulation of different technical alternatives

As discussed in chapter the balancing and ancillary services markets comes with various restrictions for power plant flexibility. Because if this, different alternatives for pump operation has been simulated in order to quantify the potential income attached to the technical alternatives. An alternative with increased flow capacity is also evaluated.

The three alternatives evaluated are:

- Alternative 1: Fixed speed pump (equal to the proposed solution in the license application)
- Alternative 2: Variable speed pump
- Alternative 3: Variable speed pump with increased flow capacity

It is assumed that there are no differences in market possibilities in production mode for the technical configurations. Therefore, income and operation plan are assumed to be identical in the winter period for alternative 1 and 2.

6.1.4 Pumping capacity as a bottleneck in the pump storage plant

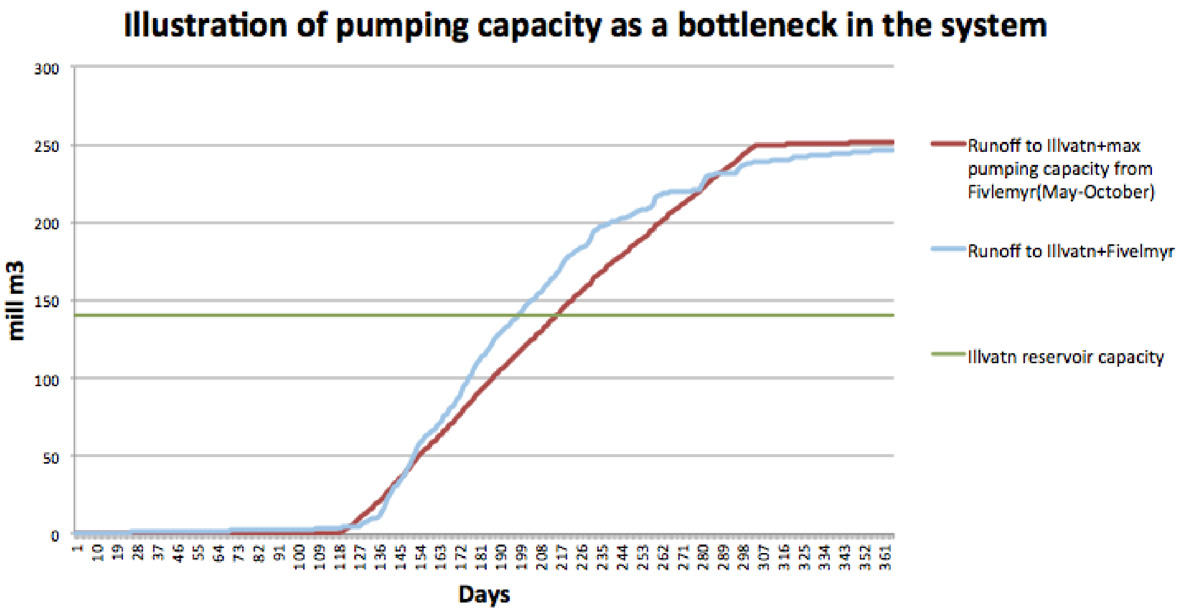

Figure 30 Illustration of bottlenecks in the system

Figure 30 illustrates the number of days necessary to fill up Illvatn reservoir in 2013. The green line is accumulated inflow to Illvatn when pumping capacity is at its maximum (12 m^3/sec) plus natural inflow to Illvatn. Pumping capacity is set to start at 1st of May and end 31st of October. The blue line is the sum of accumulated inflow to Illvatn and Fivlemyr. The purple line is maximum reservoir capacity in Illvatn, on other words the potential filling of the reservoir. As indicated the filling of the reservoir is slower when restricted by the pumping capacity of 12 m^3/sec. There is more available water for pumping in Fivlemyr than what is being utilized. This implies that pumping capacity is a bottleneck for flexible operation. The number of days until the reservoir is full with pumping capacity restriction is 213 days. The number of days until the reservoir is full, only taking into account the available water, is 193 days. In other words the difference is about 20 days. Because of this bottleneck an alternative with increased flow capacity is evaluated. Increased installed capacity will make operation more flexible and potentially lead to higher income potential because production and pumping can be placed in hours with high or low prices.

6.1.5 Assumptions for income estimation

Markets considered for income estimation is the spot market, RK market and FCR-N market. All simulations and income estimation can be said to be highly optimistic as all future prices are known and the most profitable prices are chosen for operation. Also, it is assumed that bids in the RK market are always accepted. By finding the maximum income for the power plant one can find if the project has the *potential* to be profitable or not.

6.2 Price scenario

A price scenario for the spot market and the balancing markets are developed based on literature on the subject, conversations with people within the industry and own assumptions. The price scenarios in this chapter are used for income estimation.

6.2.1 Spot market

The spot price is a result of demand and supply of electricity. On the demand side, temperature and time of the day play a significant role. On the supply side, available water for production is the most important factor. Bottlenecks in the grid can also result in higher prices and differences between price areas. Introduction of unregulated renewable energy such as run-off river and wind power in the Nordic countries as well as increased transmission capacity to the continent are likely to change the pattern for spot price.

An observation off historical spot prices is that the “price peaks” tends to happen in the winter period and the “price dips” tends to happen in the summer months. “Price peaks” refers to hours with unusually high prices and “price dips” refers to hours with unusually low prices. This can be seen in Figure 31 showing the spot prices of 2013.

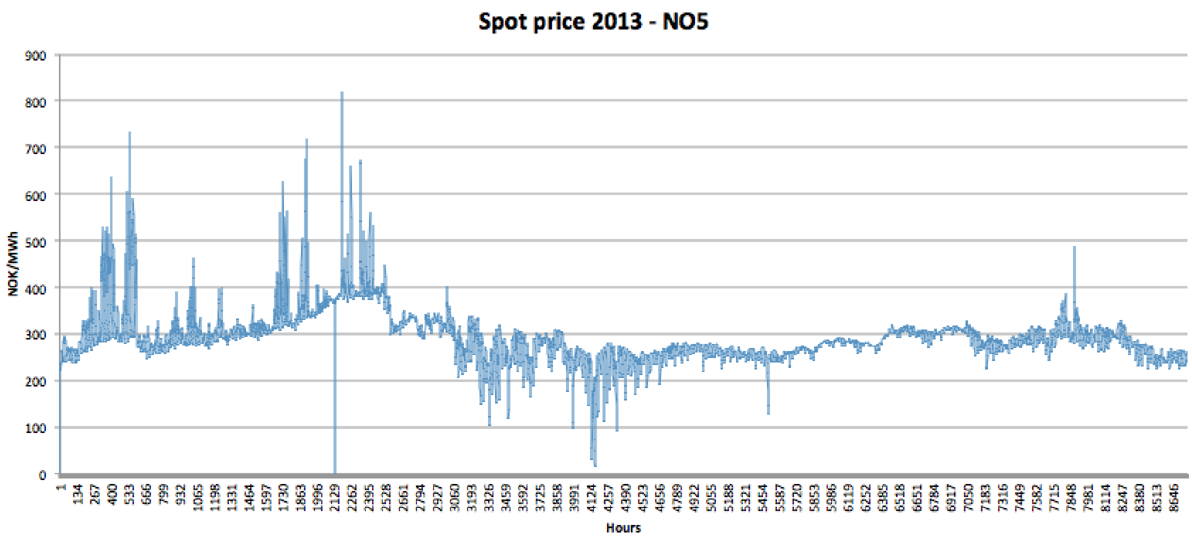

Figure 31 Spot price 2013 – NO5

A reason for this structure is likely to be that production capacity in the winter is limited. With lower temperature and higher demand in combination with limited production possibility the price is likely to go up. In the summer it is clear that there are periods with over capacity. This may be to large inflow leading the power companies to produce on maximum capacity to avoid flood spillage. Unregulated hydropower and wind power have the potential to lead to lead to over capacity on power. This in combination with low demand will lead to dips in the power price. Increased transmission capacity to England and Germany will potentially decrease this price peaks and dips because electricity can be imported and exported.

For power plant operation simulation it is of great importance to understand what is the main reasons for price variations. If one envision great change in demand caused by the transmission cables to Germany and England it is likely that price variation will occur on a daily cycle. High demand and exports during the day will lead to higher day-prices and imports of power during the night will lead to lower night-prices. If the increased price variations are however mainly caused by the increased wind power capacity and run-off-river the price variations are likely to be much more unpredictable and the price will most likely be driven by the supply side.

For this project it is assumed that the infiltration of unregulated energy production will have the biggest effect of future spot prices. The pattern of price variation can therefore not be completely linked to daily cycles. The following aspects are considered to have the most influence on the price for further operation planning and income estimation:

- Increased capacity of unregulated production (run-off river and wind power) in the summer in combination with low demand will lead to increased number of hours with low price throughout the summer.
- Increased transmission capacity will increase demand in certain hours causing hours

with high prices both in the summer and the winter, whereas the impact is most distinct in the winter with limited production capacity.

The price scenario is developed based on the historical prices for the chosen simulation period (May 2013 – April 2014). The number of hours below or above a certain percentage of the average price for each month is found. Also, the average price of the hours with price below or above is found. The result can be seen in the table below.

	May	June	July	August	September	October
Monthly avergae	279.26	250.10	258.99	258.91	283.81	299.24
70% of average	195.48	175.07	181.30	181.24	198.67	209.47
Number of hours	**28**	**53**	**12**	**0**	**0**	**0**
Average price	159.24	115.22	180.25	0.00	0.00	0.00
50% og average	139.63	125.05	129.50	129.46	141.91	149.62
Number of hours	**6**	**27**	**0**	**0**	**0**	**0**
Average price	121.53	74.22	0.00	0.00	0.00	0.00
120% of average	335.11	300.11	310.79	310.70	340.58	359.09
Number of hours	**30**	**50**	**0**	**0**	**0**	**0**
Average price	347.43	306.04	0.00	0.00	0.00	0.00
150% og average	418.89	375.14	388.49	388.37	425.72	448.86
Number of hours	**0**	**0**	**0**	**0**	**0**	**0**
Average price	0	0	0	0	0	0

Table 7 Spot prices for the summer period

The daily price variation cycle of the spot price is neglected. Instead, the number of hours each month with "extreme prices" is increased. Table 8 shows scenario for "extreme prices".

	May	June	July	August	September	October
Monthly average	279.26	250.10	258.99	258.91	283.81	299.24
70% of average	195.48	175.07	181.30	181.24	198.67	209.47
Number of hours	78	103	62	50	50	50
50% og average	139.63	125.05	129.50	129.46	141.91	149.62
Number of hours	36	57	30	30	30	30
120% of average	335.11	300.11	310.79	310.70	340.58	359.09
Number of hours	80	100	50	50	50	50
150% og average	418.89	375.14	388.49	388.37	425.72	448.86
Number of hours	30	30	30	30	30	30

Table 8 Spot price scenario for the summer period

The number of hours below 70% of monthly average is increased by 50 every month. The number of hours below 50% of monthly average is increased by 30 every month. The number of hours above 120 % of monthly average is increased by 50 every month and the number of average above 150% of monthly average every month is increased by 30 every month.

Table 9 shows the data for the winter period.

	November	December	January	February	March	April
Average	295.55	271.5	266.97	251.27	218.12	191.76
120% of average	354.66	325.8	320.364	301.524	261.744	230.112
Number	23	3	42	0	8	5
Average	363.98	327.15	350.68	0	265.97	231.48
150% of average	443.325	407.25	400.455	376.905	327.18	287.64
Number	1	0	0	0	0	0
Average	488.42	0	0	0	0	0

Table 9 Spot prices for the winter period

The number of hours with the price 120 % of the old spot price is increased by 100, and the number of hours with prices 150% of the old average is increased with 50. The price scenario can be seen in the table below.

	November	December	January	February	March	April
Average	295.55	271.5	266.97	251.27	218.12	191.76
120% of average	354.66	325.8	320.364	301.524	261.744	230.112
Number	123	103	142	100	108	105
150% of average	443.325	407.25	400.455	376.905	327.18	287.64
Number	51	50	50	50	50	50

Table 10 Spot price scenario for the winter period

Below is a graphical illustration of the spot price scenario and the historical spot prices for time period chosen for operation simulation. It is clear from the graph that the peaks and drops in the price is both increased and increased in size.

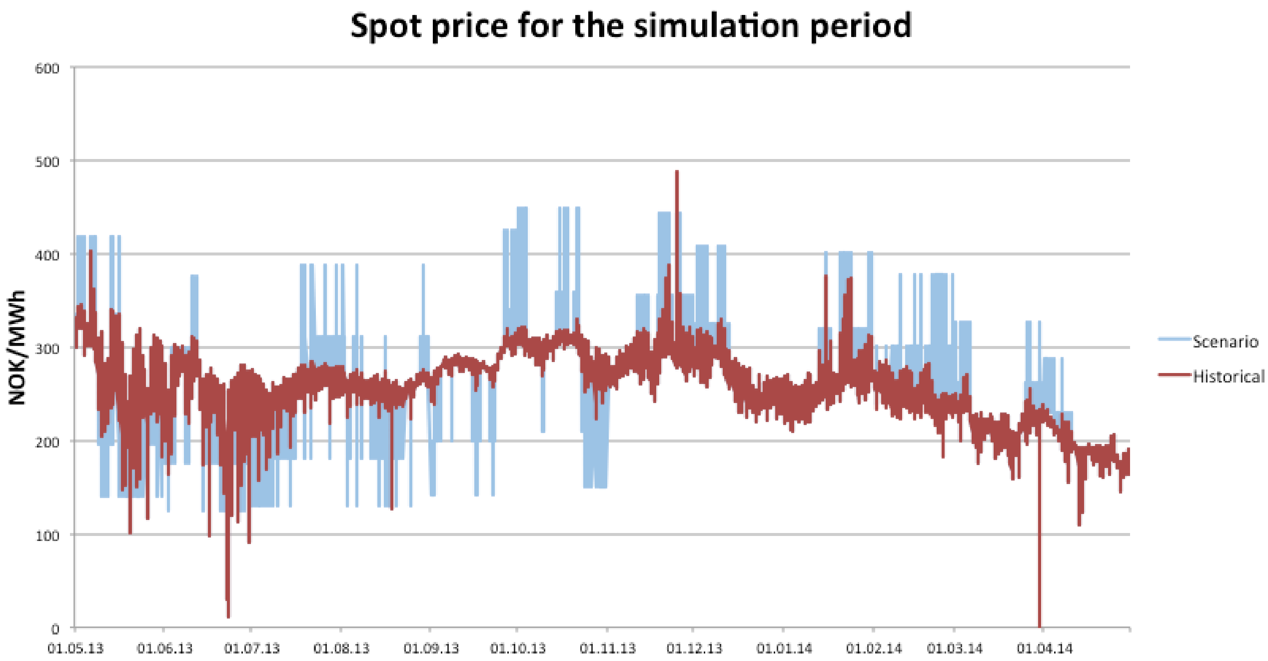

Figure 32 Spot price for the simulation period

6.2.2 Balancing markets

The balancing markets considered for simulation in this project is RK up regulating, RK down regulating and FCR day option market. Below is a graphical display on how prices varies in the chosen simulation period. The option prices for FCR do have more price peaks in the summer. The reason for this is that there will be few spinning reserves in the system with low summer- spot prices. The price for RK up and RK down have limited correlation to season and the spot price except from lower prices on down regulating in the summer.

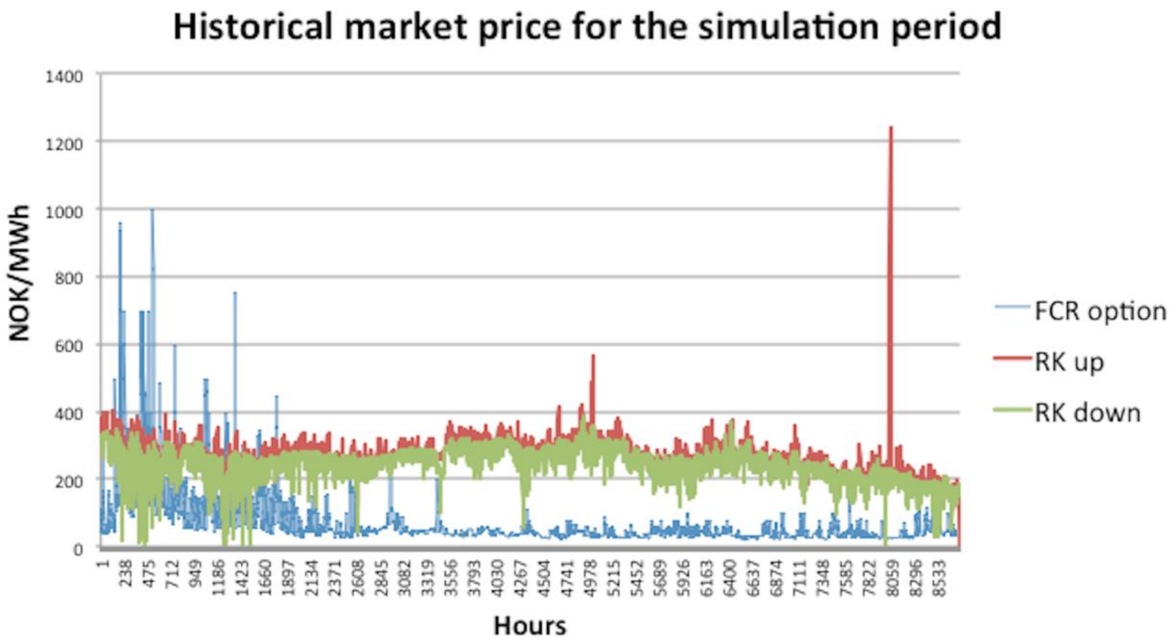

Figure 33 Historical market price for the simulation period 1st of May13- 30st of April14

Unpredictable production is also likely to cause increased demand, and thereby higher prices, for balancing markets and ancillary services in order to keep balance between production and consumption (Statnett, System og marketsutviklingsplan 2014-20, 2014). Ability to regulate generation closed to operation hour will therefore probably be profitable. However, studies show that not all balancing prices will rise. Tennebak has on request from NVE investigated the potential and consequences of cross-zonal capacity for balancing services. It is stated in the report that the potential value and prices for balancing cannot be based on historical prices because of the effect of cross-border capacity and exchange. This goes no matter if balancing services are provided on the cable. The effect of the cable for up-regulating capacity in off peak hours is illustrated in the Figure 34.

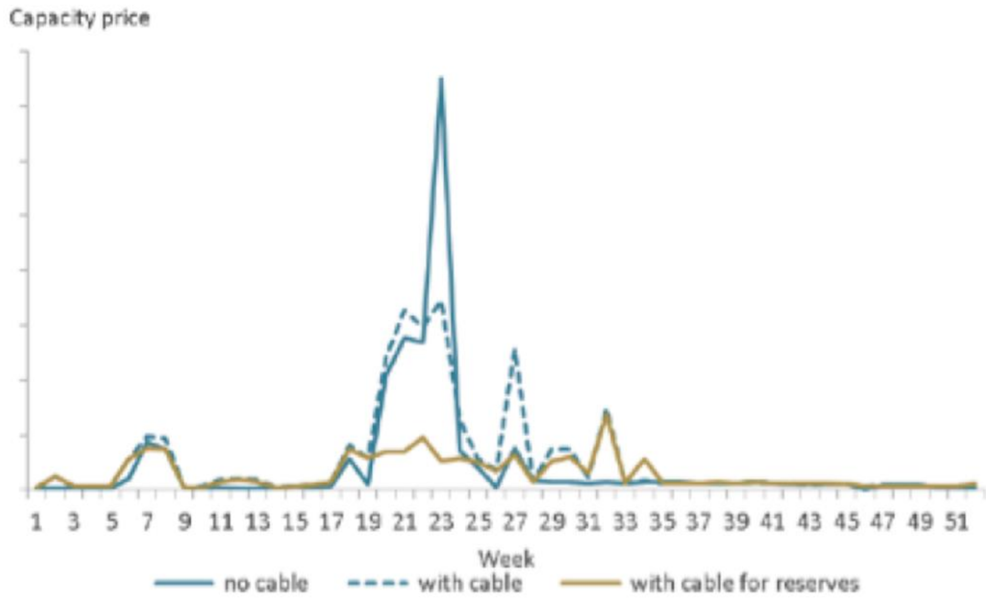

Figure 34 Balancing markets scenario (Tennebak, Reservation of cross-zonal capacity for balancing services, 2014)

The dotted line shows the price for up-regulation with cable but without capacity for reserves. The reason for the decrease in reserve price in this case is that the spot market will affect the regulating price. If the cable provides reserves the price for up-regulating services in Norway will drop even further because of more available production capacity.

The value of capacity reservation depends on a number of factors and is subject to great uncertainty. The following assumptions are used when creating balancing power market price scenario:

- The average FCR option price will decrease with 20% in the summer period. This is because of increased production capacity in the grid. The FCR option price is assumed unchanged in the winter period.
- Demand for down regulating will increase in the summer period. The reason is increased fluctuating energy production causing over-supply. The price scenario for the spot price is used as foundation for RK down price scenario. In the hours assumed to have a dip in the spot price there are assumed that there will also be demand for down regulating. The down regulating price will be 60% of the spot price. Then the minimum of the spot price and the RK down is chosen.

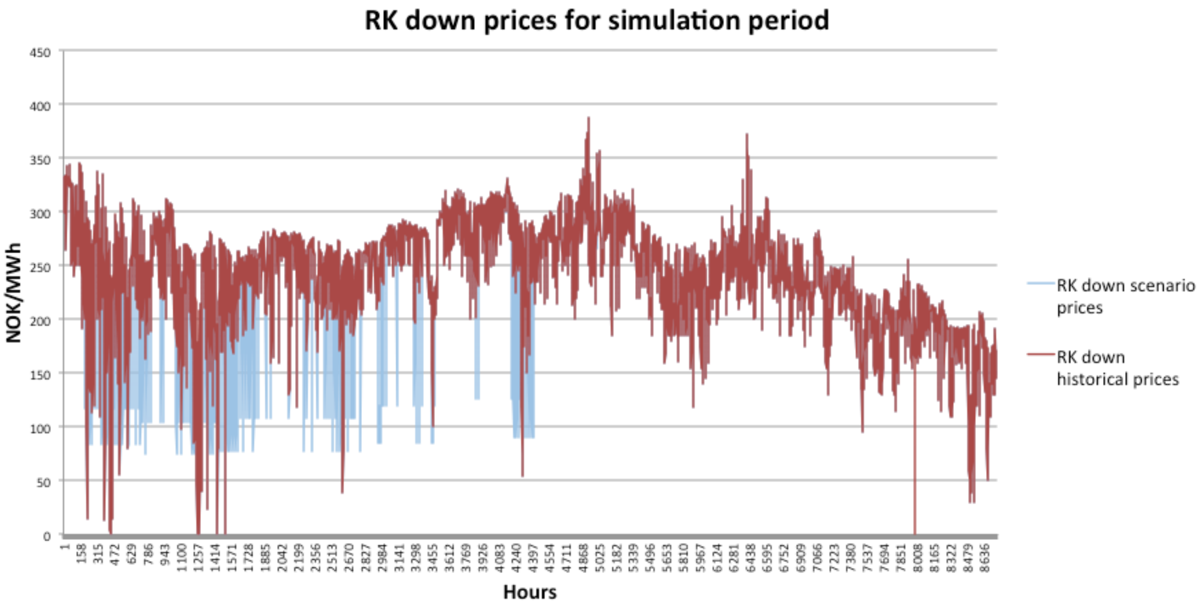

Figure 35 RK down - price Scenario

- Demand for up regulating will increase in the winter and the summer. The reason is increased demand because of international cable capacity and limited production capacity especially in the winter months. Similar to the scenario for down regulating, the spot price scenario is used for creating a up regulating scenario. In the hours assumed to have a rise in price it is assumed that there will also be demand for up regulating. The up regulating will be 120% of the spot price

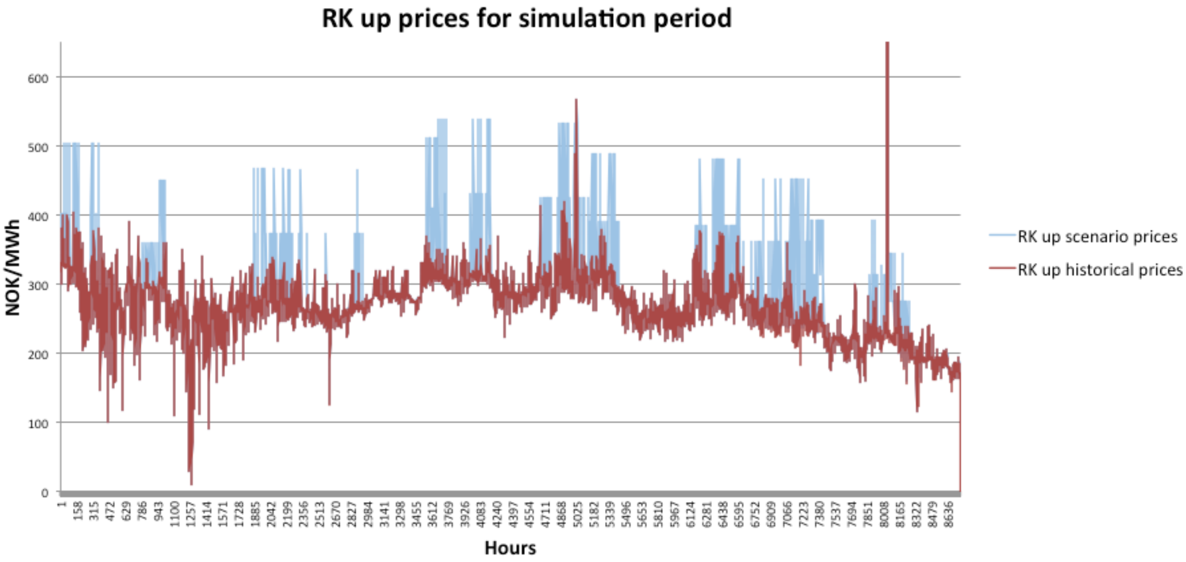

Figure 36 RK up – price scenario

6.3 Zero option alternative

In order to compare the added value from the pump power plant project, a zero option alternative is evaluated. If the Illvatn project is not inflow to Illvatn is available for production in Herva power station and later Skagen power station. Inflow to Fivlemyr is available for production in Skagen. Water storage capacity in Illvatn are sufficient for storing inflow for a whole year meaning production can happen in the most favorable hours. Flood from Illvatn is neglected. Fivlemyr reservoir has little storing capacity, only 2-3 days with natural inflow. That means production has to happen in the period with inflow, in the summer. Because of limited capacity from Fivlemyr some of the water is lost in overflow. Yearly overflow from the Fivlemyr reservoir is on average 1,1 m3/sec with a variation of +300%/-90%. This equals about 35mill m^3 yearly. Yearly average inflow data is based on the rapport "Hydrological analysis in the Fortun hydropower system" (Halim, 2007).

Figure 37 is a system description of the system today. Numbers are based on average values and are estimate numbers.

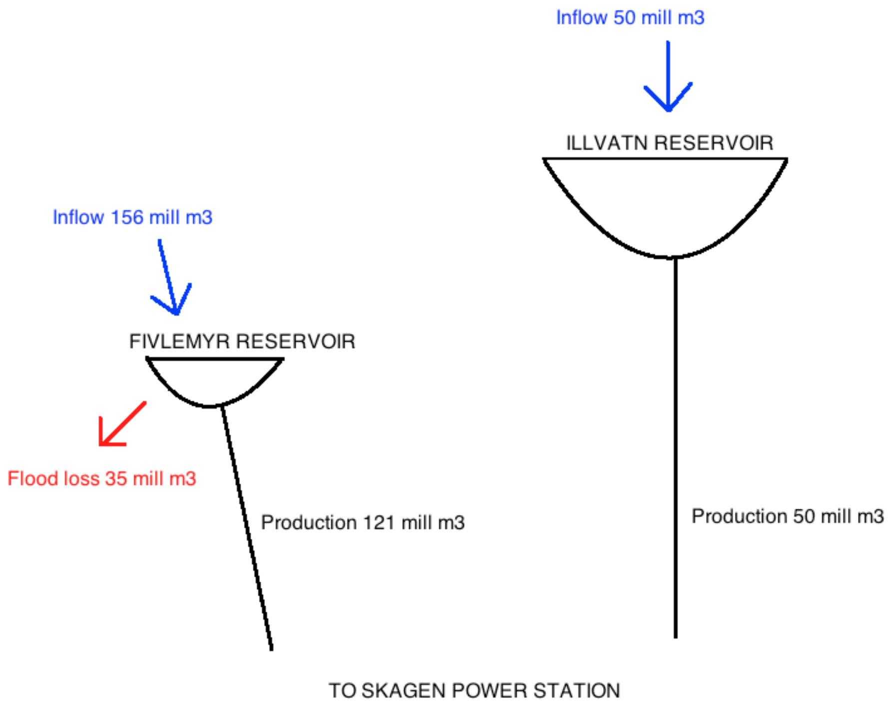

Figure 37 Zero-option system description

Energy equivalents of the water are found in order to quantify change in energy production and also potential income. The method of energy equivalents is found from the NVE guide for small hydropower (Fladen, 2010). The definition of energy equivalent is the amount of energy one can get from 1 m^3 of water through the turbine. Energy equivalents are based on height difference between reservoirs and calculated by the following methodology:

$$E_{eqv} = \rho * g * \eta * \frac{h_{net}}{3600} \tag{8}$$

Efficiency of the power plants is assumed to be 0,9. This is considered a realistic assumption for a power production estimate. Net head from Illvatn is 1355m and net head from Fivlemyr is 976m. A remark is that head loss in the waterway is not taken into account. The energy equivalents used for further calculations can be seen in Table 11.

	Water	**Energy equivalents**	**Production**
Production From Illvatn	50 mill m3	3,32 kWh/m3	166,0 GWh
Production from Fivlemyr	121 mill m3	2,39 kWh/m3	289,2 GWh
Total			**455,2 GWh**

Table 11 Production of the zero option alternative

6.3.1 Income potential for simulation period of zero option alternative

In order to compare added value of the project the income from the water resources in Illvatn and Fivelmyr is computed. As for the other simulations inflow data for the summer period of 2013 is used.

	Inflow	Water available for production	Estimated production
Fivlemyr	189,9 mill m3	121 mill m3	289,2 GWh
Illvatn	59,9 mill m3	59,9 mill m3	198,9 GWh
Total			**488,1 GWh**

Table 12 Production estimation for the zero-option alternative

The results show that 2013 was an unusual wet year compared to the average. This is illustrated in Figure 4. Average spot price for the entire period is used for income estimation. The average spot price for the historical prices is 260,6 NOK/MWh and for scenario prices it is 265,2 NOK/MWh.

	Income historical prices	Income scenario prices
Production 488,1 GWh	127 198 860 NOK	129 444 120 NOK

Table 13 Income estimation for the zero-option alternative

6.4 Energy equivalents Illvatn-Fivelmyr

For estimation of power production and income, energy equivalents for available water in the reservoirs are found.

6.4.1 Head loss in the waterway

Based on license application and earlier studies for the project, mean lifting height for the pump is 328m and mean height for the turbine is 336m. The water way consists of a diversion tunnel and a steel lined pressure shaft. The tunnel has a length of 7500 m and cross section 20m^2. Friction loss in tunnels is calculated using Manning’s formula:

$$h_{loss} = \frac{L * Q^2}{M^2 * A^2 * R^{1,33}} \tag{9}$$

According to (Fladen, 2010) Manning number 33 can be used for blasted tunnels. According to (Guttoromsen) R=0,265√A is an accepted simplification for ordinary tunnel cross sections. The resulting head loss in the tunnel calculated with formula 9 and is 3,27m.

The steel lined pressure shaft has a length of 70 m. For pipes Darcy Weissbachs formula is used for calculating head loss.

$$h_{loss} = \lambda \frac{L * C^2}{D * 2g} \tag{10}$$

The friction coefficient 0,015 for a steel pipe can be used for estimates according to (Fladen, 2010). The steel pipe has a diameter of 2 m, the length is 50m and average velocity at maximum flow is 4,8 m/sec. The resulting head loss in pressure shaft is therefore 0,24m.

Total head loss in the waterway is then 3,71 m. The head loss is rounded up to 4m in further calculations. Singular losses are neglected.

6.4.2 Pump turbine efficiency

Hydro Energy has evaluated the efficiency in pumping and turbine operation for different technical alternatives. Efficiency in pumping operation and production operation varies with technical design and flow. The efficiency of the turbine decreases on partial load. It is possible to increase the efficiency on partial load by installing a frequency converter. The efficiency curve for variable speed shows less variation than the curve for fixed speed. On the other hand, the frequency converter itself has an efficiency of about 99%, meaning it will reduce the total efficiency on optimal load and rated speed. The turbine does however not always operate on optimal load and increased efficiency on partial load may overall be the optimal solution.

Figure 38 and 39 show turbine efficiency curves for two different net heights, 300m and 332m.

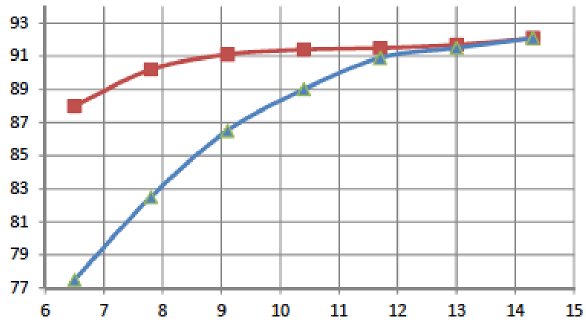

Figure 38 Turbine efficiency H=300m, m^3/sec on the x axis and %efficiency on the y axis

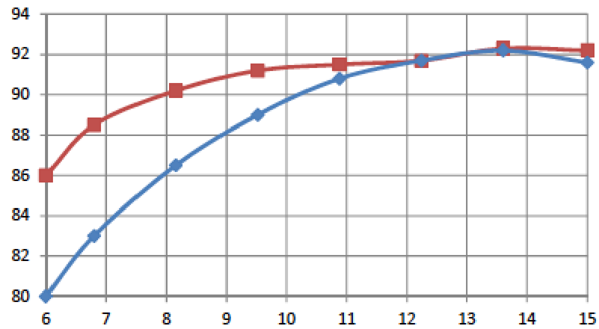

Figure 39 Turbine efficiency H=332m, m^3/sec on the x axis and %efficiency on the y axis

The efficiency of the pump show little variation with variable flow and is above 90% for flow between 9-12 m^3/sec. In order to decrease the flow below 9 m^3/sec and at the same time maintains fairly good efficiency a frequency converter can be installed. The variable speed pump will then adjust to the flow. The drawback is the same as for the turbine; the frequency converter itself has an efficiency of 99%, resulting in a lower efficiency for the pumping.

For simplification reasons constant turbine and pump efficiency and thereby a constant energy equivalents is used for further calculations. Simulation of the power plant aims to find the income potential and therefore operation at best efficiency is assumed. For production, a turbine efficiency of 92% is assumed for further calculations. The flow corresponding with this efficiency is about 13,5m^3/sec. For the pump an efficiency of 90% is assumed for fixed speed pump. For a variable speed pump with an installed frequency converter the efficiency will be 89% with a net loss of 1% in the converter. The flow corresponding with this efficiency is assumed 11m^3/sec.

6.4.3 Results

Energy equivalents are calculated with formula 8. For production between Ilvatn and Fivlemyr the energy equivalent is 0,83 kWh/m^3.

Energy equivalents for pumping operation are found by the following methodology:

$$E_{eqv} = \rho * g * \frac{1}{\rho} * \frac{h_{net}}{3600} \tag{11}$$

Because of different efficiency the energy equivalent for pumping with a fixed speed pump is 1,00 kWh/m^3 and 1,02 kWh/m^3 for a variable speed pump.

6.5 Estimated increased production after project realization

Figure 40 is a system description after project realization. Numbers are based on average hydrological values and are estimate numbers. Increase in annual production is estimated.

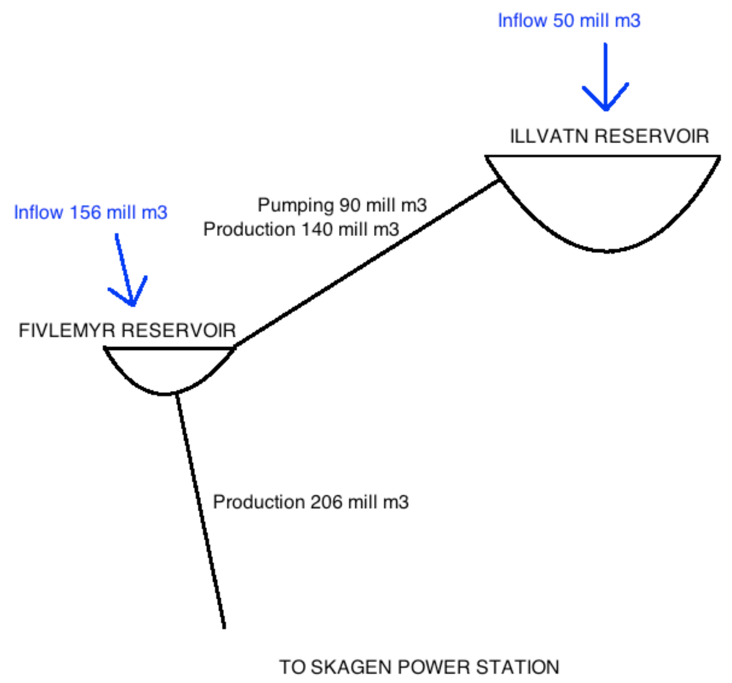

Figure 40 System description after project realization

The water produced in Fivlemyr power plant has a residual value based on the possibility for increased production in Skagen power plant. The energy equivalent from Fivlemyr to Skagen is calculated with formula 8 and is 2,39 kWh/m^3.

For estimation of increased of production, the energy equivalent of the fixed speed pump is used. The power used for pumping with a variable speed pump will be somewhat more as the frequency converter has 99% efficiency.

	Water	Energy equivalents	Production
Pumping Fivlemyr-Illvatn	90 mill m3	1,00 kWh/m3	-90,0 GWh
Production Illvatn-Fivlemyr	140 mill m3	0,83 kWh/m3	116,2 GWh
Production from Fivlemyr	206 mill m3	2,39 kWh/m3	492,3 GWh
Total			**518,5 GWh**
Yearly average increase in production from zero-option alternative			**63,3 GWh**

Table 14 Production estimation after project realization

Based on the energy equivalents calculated, pumping operation between Fivlemyr and Illvatn proves to be very convenient. The energy equivalent for pumping from Fivlemyr to Illvatn is 1 kWh/m^3. The water available for production in Illvatn has a energy equivalent of 3,22kWh/m^3.

6.6 Winter period

6.6.1 Simulation strategy

Only production mode is possible in the winter period. It is assumed that the turbine offers relatively high degree of flexibility and therefore market possibilities in various markets. The markets considered for simulation and income estimation in the winter period is spot market, RK up regulating market and FCR day option market. The simulation method used in this project is a simplification of what would have been the case in real life. RK down regulating is not considered. This is partly because of simplification of the model and partly because the main reason for using RK down is that the power producers expect the price to rise on a later time. The simulation in this project has a perfect foresight on market prices, it can therefore be said that the purpose with RK down regulating is superfluous. The option markets for RK regulating such as RKOM season and RKOM week is also excluded from simulation for simplification reasons as participation in this markets are limiting operation.

Capacity of the power plant is calculated as follows:

$$P = h_{net} * q * g * \eta * \rho \tag{11}$$

Installed capacity of the turbine is 48MW. For simulation it is assumed that the turbine will operate on best point with a flow of 13,5 m3/sec. With the head loss and efficiency taken into account the operating capacity will then be 40,4MW. Simulation on power plant operation is done both on historical prices and the scenario prices. The method for power plant operation during the winter for is done by the following steps:

1. Find hourly income per MW for the following combinations:
   a. 40,4MW in spot market,
   b. 40,4MW sold in RK up regulating market
   c. 30,4MW sold in spot market+10MW sold in FCR day option market. For this combination the income price has to be divided on 30,4MW since this is the only energy that is being sold.

2. The sum of power production for the entire period should be enough to empty Illvatn reservoir by the end of the period. Total reservoir capacity, 140mill m^3, is transformed into energy by using the energy equivalent 0,83kWh/m^3. Energy for production in the winter period is then 116 200MWh.

3. Sort all prices in decreasing order. Place capacity in the most profitable hours/markets. It is expected that bids are always accepted in the RK up regulating market and the entire volume is sold to the market price.

6.6.2 Income estimation

	Historical prices	**Price scenario**
Income from RK up regulating	11 471 588 NOK	22 942 177 NOK
Income from FCR day option	907 510 NOK	595 410 NOK
Income from spot market	20 384 220 NOK	13 407 068 NOK
Total income	**32 763 318 NOK**	**36 944 655 NOK**

Table 15 Income potential winter period

6.6.3 Simulation only in the spot market

As a separated simulation considering only spot market is done for the winter operation. The purpose is to get a feeling of what the added income from alternative markets are and to find out if it really is worth taking into account for investment analysis.

	Historical prices	**Price scenario**
Total income	**31 686 041 NOK**	**33 054 369 NOK**

Table 16 Income potential spot market

6.6.4 Discussion of result

The power plant is operating in 80%of the hours when simulating on historical prices and 76% of the hours with scenario prices. Selling all capacity in the spot market is not the best alternative for any of the hours. This goes both for the historical prices and the scenario prices. Income from spot market is however obtained by selling 10MW for FCR capacity and 30,4MW in the spot market. The average price per MW by this combination is the best alternative in 73% of the operating hours for historical prices and 51% of the operating hours for the scenario prices. The decrease in total operating hours is a consequence of increased profitability in the RK market and decreased profitability in the FCR market. With decreased profitability in the FCR market the power producer will allocate more resources in the wholesale energy market, which means shorter operation time.

Distribution between markets changes considerably when comparing historical prices and price scenarios. While most of the income when simulating based on historical prices comes from the spot market, most of the income comes from the RK market when simulating on scenario prices.

Income from FCR day option is reduced as the price scenario for FCR option entails decreased FCR option prices. Reduced FCR option prices can also be said to be one of the reasons why the number of hours when selling power in the spot market, and the total income from the spot market is reduces.

The optimal operation of the power plant entails many starts and stops. Weather this can be said to be realistic in a real situation depends on the chosen technical configuration. The advantage with this kind of flexibility for the turbine mode is that one will get a total income when only the hours with the highest prices are chosen. The price scenarios created do especially favor this kind of flexibility as the price peaks are few and of substantial size.

Total income is increased when balancing markets, RK market and FNR option market, is included in the simulation both for historical prices and the price scenario. The potential is increased by 3% when simulating with historical prices and 12% when simulating with scenario prices.

6.7 Alternative 1 – Fixed speed pump

6.7.1 Simulation strategy summer period

For a fixed speed pump only the spot market are considered for pumping operation and income estimation as the pump offers a low degree of flexibility. Also, the starts and stops of the pump are limited

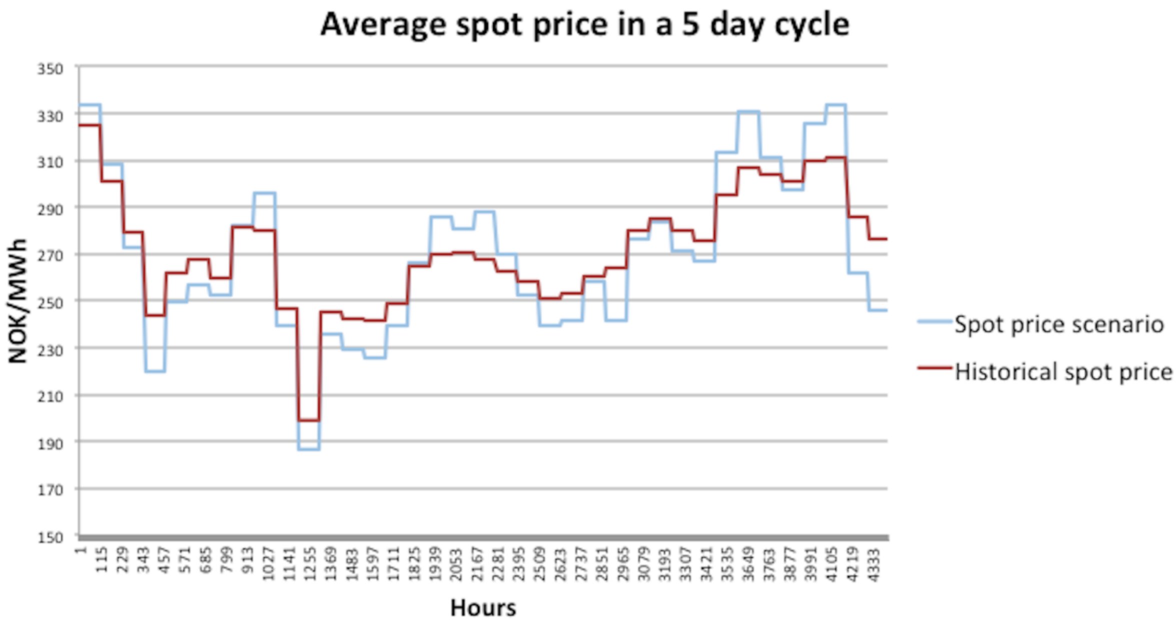

Figure 41 Average spot price in a five day cycle

The capacity of the pump is calculated with Formula 11. With the assumed flow, head loss and efficiency the resulting operating capacity is 32,3MW. The method for simulation and income estimation is as follows;

1. In order to limit the number of starts and stops in simulation the average spot price for groups of 5 days is found. The result is illustrated in Figure 41.

2. Required pumping volume is transformed into power and necessary pumping hours. Natural inflow to Illvatn in the summer period was 59,9 mill m^3, and reservoir capacity is 140 mill m^3. This means that a total of 80,1 mill m^3 need to be pumped up from Fivlemyr in order to fill up the reservoir. By using the energy

equivalent found from earlier (1,0 kWh/m^3) the necessary energy for pumping from Fivlemyr to Illvatn is about 80 100MWh.

3. Sort all average prices in a five-day cycle. The periods (groups of 5 days) with the lowest spot price will be the chosen for pumping operation. Place pumping operation in the hours with the lowest spot price and make sure total pumping volume is equal to 80,1 mill m3.

For calculation of added income form production in Skagen the average spot price over the whole period is used. The average spot price from the historical prics is 260,6 NOK/MWh and 265,6 NOK/MWh for the scenario prices. With the pump power plant installed, all inflow to Illvatn and Fivlmeyr are useable later in the system. Total inflow for Illvatn and Fivlemyr in the simulation period is 249,8 mill m3. With inflow data from the summer period, the total production in Skagen arising from the inflow to Illvatn and Fivlemyr is 589,9 GWh.

6.7.2 Pumping strategy compared to inflow data

Daily pumping operation does not take into account available inflow to Fivlemyr. Therefore simulated monthly pumping volume is checked against sum of monthly inflow to Fivlemyr. As shown, pumping volume never exceeds inflow.

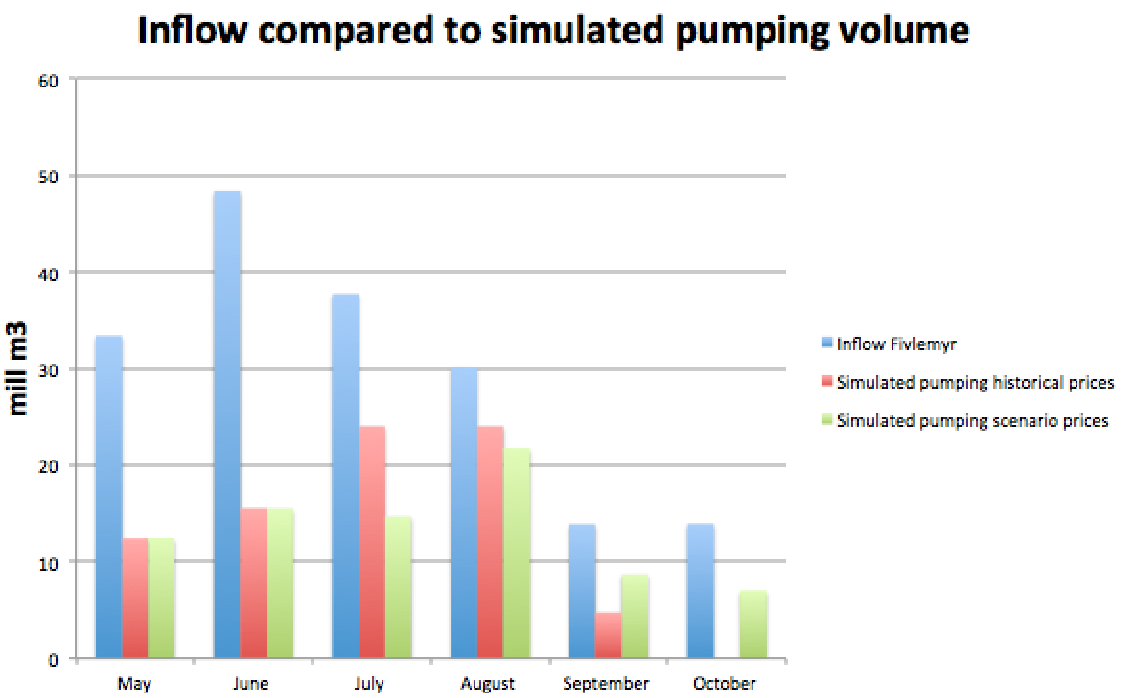

Figure 42 Inflow compared to simulated pumping volume

Simulated pumping volume is less than inflow to Fivlemyr for every month. Variations on smaller timescale such as daily or hourly inflow verses simulated pumping volume are not controlled.

6.7.3 Income estimation

	Historical prices	**Price scenario**
Summer period	-20 572 040 NOK	-19 633 756 NOK
Winter period	32 763 318 NOK	36 944 655 NOK
Added income from production in Skagen	153 727 940 NOK	156 677 440 NOK
Total	**165 919 218 NOK**	**173 988 339 NOK**

Table 17 Income potential Alternative 1

6.7.4 Discussion of result

The cost of pumping decreases a little when simulation is done on the price scenario. The reason for this is that the price drops are increased in number and in size which makes pumping cheaper.

6.8 Alternative 2 – Variable speed pump

6.8.1 Simulation strategy summer period

With a variable speed pump one has increased flexibility in pumping mode compared to a fixed speed pump. The objective for the summer operation is to minimize the cost of pumping. The markets considered for simulation in this project are spot market, RK down regulating and FCR day option. The operation capacity is found by Formula 11 and is 31,9MW.

The method for power plant simulation during the summer for variable speed pump is done by the following steps:

1. Find hourly cost/income for the following combinations of markets;
   a. 31,9MW pumping in spot market,
   b. 31,9MW pumping in RK down regulating market

    c. 21,9MW pumping in spot market and 10MW option in the FCR day market

2. Required pumping volume is transformed into power and necessary pumping hours. Natural inflow to Illvatn in the summer period was 59,9 mill m^3, and reservoir capacity is 140 mill m^3. This means that a total of 80,1 mill m^3 need to be pumped up from Fivlemyr in order to fill up the reservoir. By using the energy equivalent found from earlier (1,02 kWh/m^3) the necessary energy for pumping from Fivlemyr to Illvatn is about 81 700MWh.

3. Pumping on RK down regulating is the far most profitable way to fill up Illvatn reservoir as it entails an income instead of a cost. It is assumed that bids in the RK are given in 50% of the required pumping power (40 800MWh), and always accepted by system operator. To find the maximum potential, the RK down prices are sorted in decreasing order and 50% of the required pumping hours are chosen to be the most profitable RK down prices.

4. The rest of the required pumping hours are either bought in spot market, or a combination of buying power in the spot market and selling FCR option.

6.8.2 Pumping strategy compared to the inflow data

Daily pumping operation does not take into account available inflow to Fivlemyr. Therefore simulated monthly pumping volume is checked against sum of monthly inflow to Fivlemyr. As shown, pumping volume never exceeds inflow.

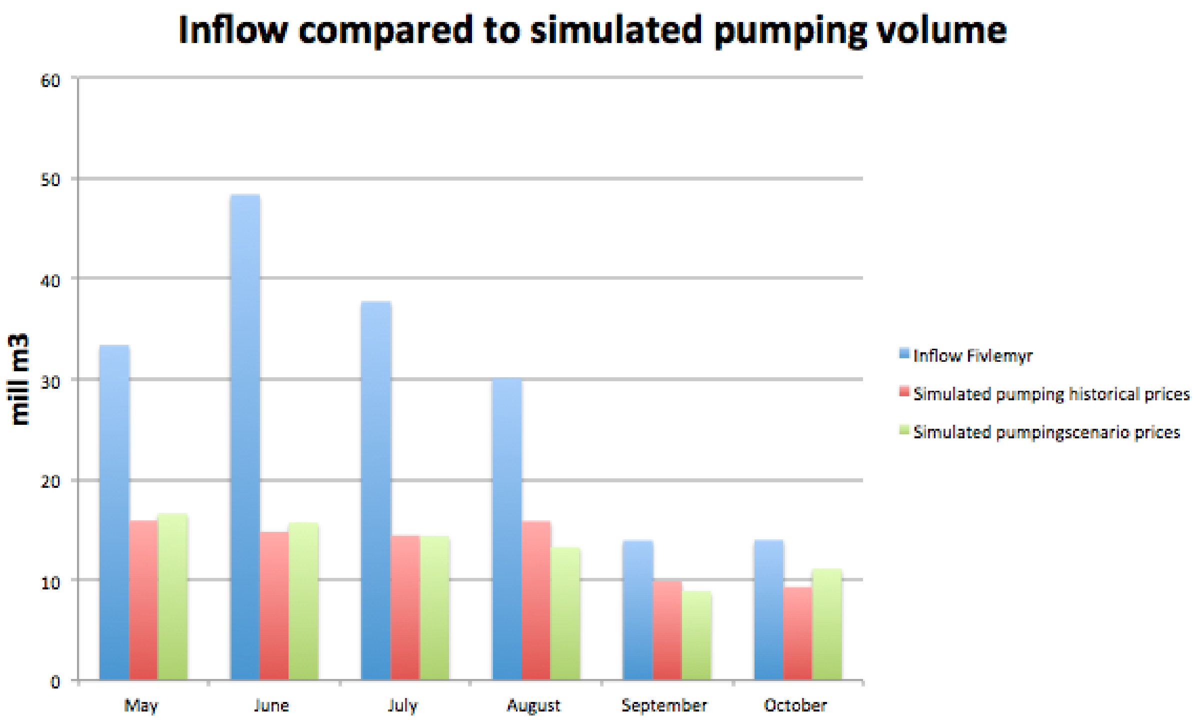

Figure 43 Inflow compared to simulated pumping volume

Variations on smaller timescale such as daily or hourly inflow verses simulated pumping volume are not controlled.

6.8.3 Income estimation

	Historical prices	**Price scenario**
Income from RK down regulating	10 553 801 NOK	11 202 437 NOK
Income from FNR day option	1 394 785 NOK	2 155 944 NOK
Income from spot marked	-10 086 177 NOK	-9 263 709 NOK
Total summer period	**1 862 409 NOK**	**4 094 672 NOK**
Total winter period	32 763 318 NOK	36 944 655 NOK
Added income from production in Skagen	153 727 940 NOK	156 677 440 NOK
Total income	**188 353 667 NOK**	**197 716 767 NOK**

Table 18 Income potential Alternative 2

6.8.4 Discussion of results

The cost of pumping decreases remarkable during the summer period compared to a fixed speed pump due to the possibility of participating in balancing markets. Income from RK down regulating is the far most profitable market for pumping operation because producers are paid for power consumption. In this simulation is it assumed that bids in the RK down regulating market is accepted for 50% of the total pumping power needed to fill up Illvatn.

Income from FNR day option market reduces the cost per MWh of pumping. Because of reduced FNR option prices in the price scenario income from FNR is reduced when simulating on price scenario. Cost of pumping on spot market is reduced when simulating on the price scenario.

6.9 Alternative 3 – Variable speed pump with increased flow capacity

The bottleneck of the pumping capacity may lead to less flexibility of operation and possibly lower income potential. Therefore income with increased capacity on pumping and production is evaluated. With increasing the maximum flow capacity one can optimize operation and place pumping and production to the most favorable hours.

An alternative of maximum 25,0 m^3/sec flow capacity in turbine mode and 20 m^3/sec in pumping mode is evaluated. In chapter 7.3 the tunnel and pressure shaft are optimized based on this flow. The head loss in the waterway is calculated in chapter 7.3.1.1. As for the previous alternatives, it is assumed that the average flow will be 90% of maximum potential in order to have maximum efficiency. That means 22,5 m^3/sec in turbine mode and 18,0 m^3/sec in pumping mode. The pump is a variable speed pump with the same efficiency as in alternative 2.

Operation capacity for production simulation is calculated with formula 11 and is 67,2MW. Pump operation capacity for simulation is 52,9MW. Energy equivalents for production is calculated with formula 8 and is 0,83 kWh/m^3. Energy equivalents for pumping is calculated with formula 11 and is 1,02 kWh/m^3.

6.9.1 Winter period simulation

The method for power plant operation during the winter for variable speed pump is done by the following steps:

1. Find the income per MWh of production for the following combinations
    a. 67,2MW in spot market
    b. 67,2MW sold in RK up regulating market and
    c. 57,2MW sold in spot market+10MW sold in FCR day option market. With this combination 10MW in FCR day option and 57,2MW sold in the spot market, the income price has to be divided on 57,2MW since this is the only energy that is being sold.
2. The sum of power production for the entire period should be enough to empty Illvatn reservoir by the end of the period. Total reservoir capacity, 140mill m3, is transformed into energy by using the energy equivalent 0,83kWh/m^3 (calculated earlier in the chapter). The production power during the winter is then 116 200MWh.
3. Sort all prices in decreasing order. Place capacity in the most profitable hours/markets. It is expected that bids are always accepted in the RK up regulating market and the entire volume is sold to the market price.

6.9.2 Summer period simulation

The method for power plant operation during the summer period for fixed speed pump is done by the following steps:

1. Find hourly cost/income for the following combinations of markets;
    a. -52,9MW pumping in spot market,
    b. -52,9MW pumping in RK down regulating market
    c. -42,9MW pumping in spot market and 10MW option in the FCR day market

2. Find required energy for pumping in order to fill up Illvatn reservoir. The energy equivalent for pumping is 1,02kWh/m3 and the necessary volume is 80,1m3. This means that the total energy for pumping is 81 700MWh.

3. Pumping on RK down regulating is the far most profitable way to fill up Illvatn reservoir as it entails an income instead of a cost. It is assumed that bids in the RK are given in 50% of the required pumping power (40 800MWh), and always accepted by system operator. To find the maximum potential, the RK down prices are sorted in decreasing order and 50% of the required pumping hours are chosen to be the most profitable RK down prices.

4. The rest of the required pumping hours are either bought in spot market, or a combination of buying power in the spot market and selling FCR option. For the latter alternative it is set that the pumping in the spot market will be -42,9MW and the sold flexibility in the FCR option market will be 10MW. The prices for these to alternatives are found for every hour.

5. Find the price/MW of pumping for buying -52,9MW in the spot market and buying -42,9MW in the spot market plus 10MW in the FCR market. Sort the prices in decreasing order and chose the cheapest hours for pumping operation.

6.9.3 Pumping strategy compared to the inflow data

With increased flow capacity there is a chance that potential pumping and simulated pumping volume will exceed inflow to Fivlemyr. As for the other alternatives, simulated monthly pumping volume and inflow are compared.

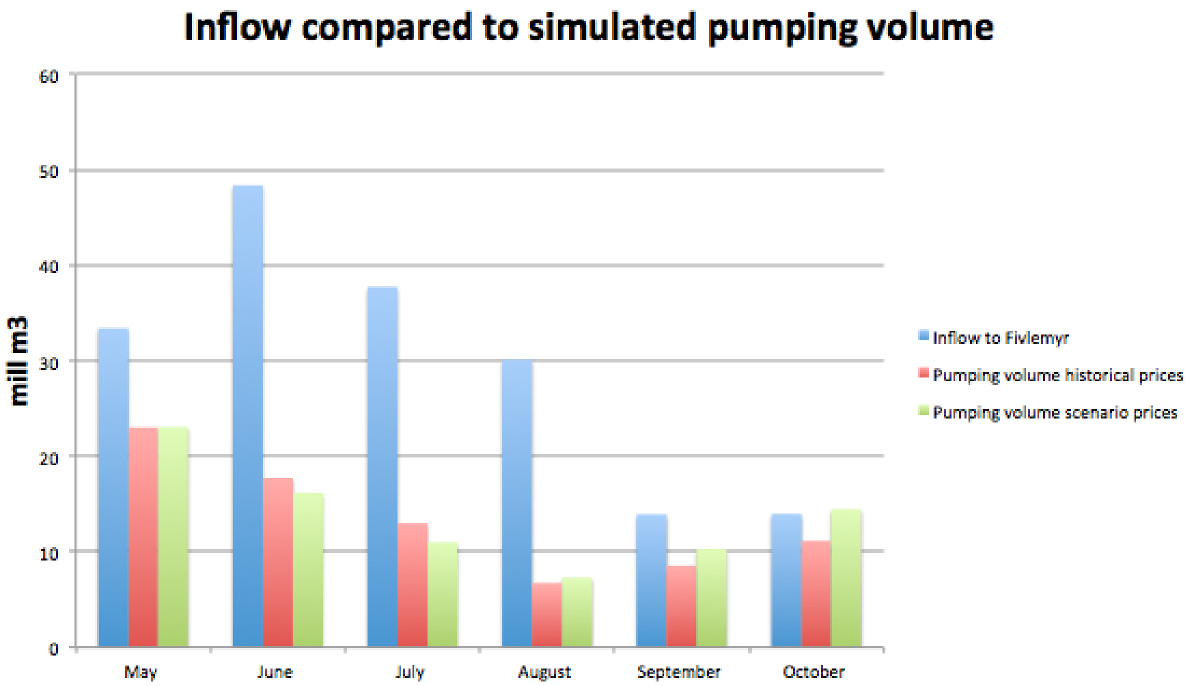

Figure 44 Inflow compared to simulated pumping volume

Pumping volume is barely higher than natural inflow to Fivlemyr in October.

6.9.4 Income estimation

	Historical prices	**Price scenario**
Summer period	3 685 403 NOK	5 220 558 NOK
Winter period	35 240 656 NOK	41 000 767 NOK
Total Fivlemyr-Illvatn	38 926 059 NOK	46 221 325 NOK
Added income from production in Skagen	153 727 940 NOK	156 677 440 NOK
Total	**192 653 999 NOK**	**202 898 765 NOK**

Table 19 Income potential Alternative 3

6.9.5 Comments on the results

Income increases remarkable when simulating on the price scenario. The reason is that one can take better advantage of the price peaks with increased capacity and the number of price peaks is increased in the price scenario.

6.10 Sum up income estimation with the different alternatives

Technical alternative	**Income**	
	Historical prices	**Price scenario**
Zero-option alternative	127 198 860 NOK	129 444 120 NOK
Alternative 1 – Fixed speed pump	165 919 218 NOK	173 988 339 NOK
Increase from zero-option alternative	**38 720 358 NOK**	**44 544 219 NOK**
Alternative 2 – Variable speed pump	188 353 667 NOK	197 716 767 NOK
Increase from zero-option alternative	**61 154 807NOK**	**68 272 647 NOK**
Alternative 3 – Fixed speed pump increased flow capacity	192 653 999 NOK	202 898 765 NOK
Increase from zero-option alternative	**65 455 139 NOK**	**73 454 645 NOK**

Table 20 Income potential with different technical alternatives

Alternative 3, with increased flow capacity and variable speed pump has the largest increase in yearly income compared to the zero-option alternative. The fixed speed alternative is the alternative with the smallest income potential. For all the alternatives simulation on price scenario prices has greater income potential than simulation on historical prices.

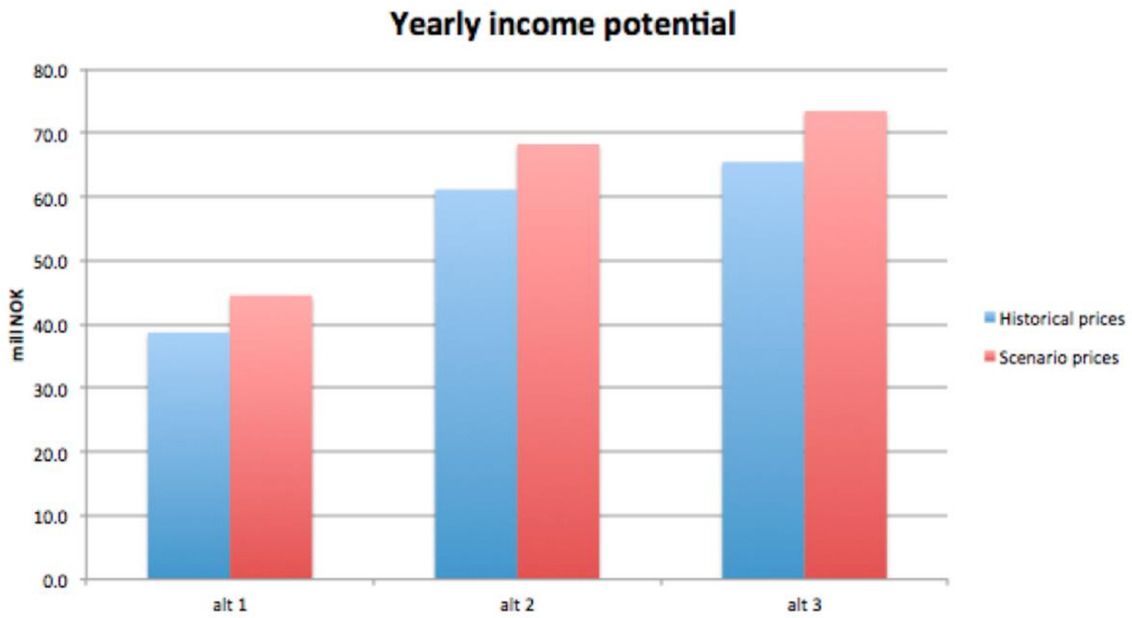

Figure 45 Yearly income potential with different technical alternatives

The calculated incomes are maximum increase in income potential. It is not realistic than one is able to obtain the yearly incomes calculated as the income estimations are based on simulation with "perfect foresight" on the prices. Below is a table when the income is reduced in order to get a more realistic investment analysis. Estimates are in million NOK.

	100%		**80%**		**60%**	
	Historical	**Scenario**	**Historical**	**Scenario**	**Historical**	**Scenario**
Alternative 1	38,7	44,5	31,0	35,6	23,2	26,7
Alternative 2	61,2	68,3	48,9	54,6	36,7	41,0
Alternative 3	65,5	73,5	52,4	58,8	39,3	44,1

Table 21 Income estimation for investment analysis

7 Investment cost and variable cost

This chapter aims to quantify investment cost and variable costs associated with different technical alternatives. Variable costs indicate costs for operation and maintenance. It is assumed that the operating and maintenance cost are directly linked to the power plant operation and the number of starts and stops because of increased abrasion. For this project it is assumed that the cost of one start/stop cycle will be 1000 NOK. The number of start and stops for each alternative is found and the costs are used in combination with the income potential to find the yearly net cash flow.

As described in chapter 6.1.3 the three technical alternatives evaluated are

- Alternative 1: Fixed speed pump
- Alternative 2: Variable speed pump
- Alternative 3: Variable speed pump with increased flow capacity

Alternative 1 with fixed speed pump is based on project information in the license application. Alternative 2 and 3 are variations of alternative 1 with increased degree of flexibility. Estimation of costs are based on the cost basis from NVE and discussions with people from Hydro Energy.

Cost estimation from the license application is given in 2010 value. All additional costs are calculated based on NVEs cost basis from 2010 or empirical figures from Hydro Energy. The costs are adjusted with the consumer price index (CPI) found from SSB. This is done to take economical inflation into account. The CPI from 2010 to January 2015 is 7%.

7.1 Alternative 1 – Fixed speed pump

7.1.1 Civil work

The waterway in the license application consists of a 7500m tunnel from the intake and 800m drainage tunnel. Cross section of the tunnel is 20-22m^2. A steel lined pressure shaft with a length of 50m is leading in to the power station. A power station built in hard rock is planned.

7.1.2 Mechanical works

Planned capacity is 48MW in turbine mode and 39MW in pumping mode. Seasonal pumping is the main purpose with the project and a fixed speed pump is therefore considered a suitable solution. Flow capacity in turbine mode is 15m^3/sec and 12m^3/sec.

7.1.3 Electro

Based on planned installed capacity of 48MW and 39MW for the pump storage power plant a synchronous induction machine has been considered. Soft starter has been considered as the start-up method for pumping operation. Start-up time for this method is according to the suppliers questioned about 5-7 minutes and a limited number of start-ups of the pump is possible during the year.

7.1.4 Investment costs

Specification	**Cost**
Civil work	260 mill NOK
Mechanical work	65 mill NOK
Electro work	70 mill NOK
Design cost and developer cost (high estimate)	60 mill NOK
Project reserves (high estimate)	115 mill NOK
Total cost with 2010 price level	**570 mill NOK**
Total (CPI=7%)	**609 900 000 NOK**

Table 22 Cost estimation Alternative 1

7.1.5 Operating and maintenance cost

In order to maximize income the operation plan over the year is as follows.

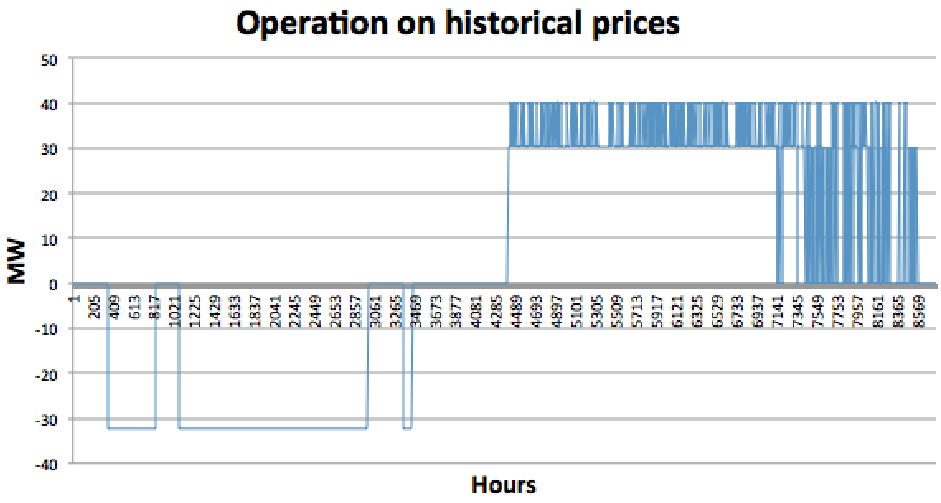

Figure 46 Operation on historical prices, Alternative 1

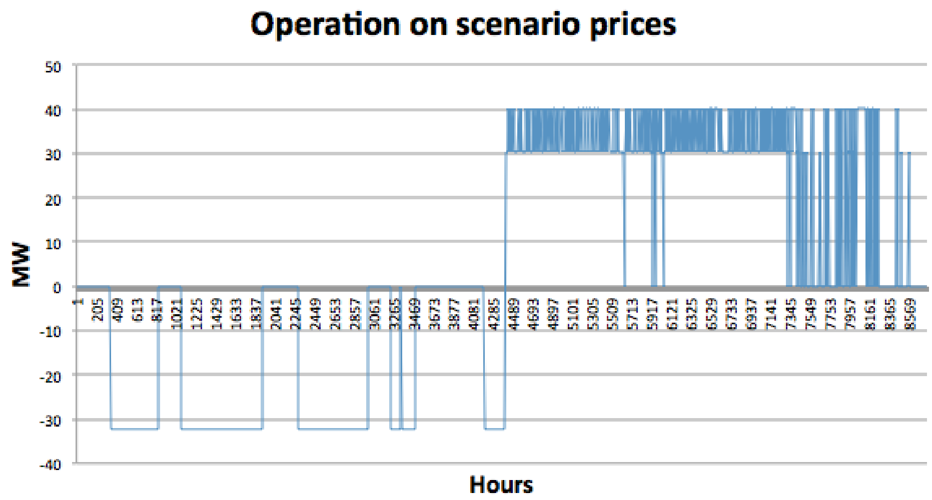

Figure 47 Operation on scenario prices, Alternative 1

The number of start/stops for the historical prices is 69 and 61 for scenario prices. That means that yearly variable cost are 69 000 NOK with simulation on historical prices and 61 000 NOK with simulation on scenario prices.

7.2 Alternative 2 – Variable speed pump

Implementation of a frequency converter is considered the only change in technical design compared to Alternative 1.

7.2.1 Investment costs

A variable speed pump will result in a higher investment cost compared to a fixed speed pump. Both increased civil costs because of the necessity of bigger power hourse and cost for the frequency converter is the reason for this. Hydro Energy estimates that a frequency transformer will result in an increase of 10-20mill NOK in the investment costs. An extra cost of 20 mill NOK is used in the following in order to get a more conservative estimate. Extra technical equipment in the power station will result in the need for increased space. For the civil costs it is assumed 5% increase compared to Alternative 1 due to this.

Component	Cost
Earlier estimate	609,9 mill NOK
Increase because of installation of frequency converter	20 mill NOK
Increase in civil costs	13 mill NOK
Total	**642 900 000 NOK**

Table 23 Cost estimation Alternative 2

7.2.2 Operating and maintenance cost

In order to maximize income the operation plan over the year is as follows.

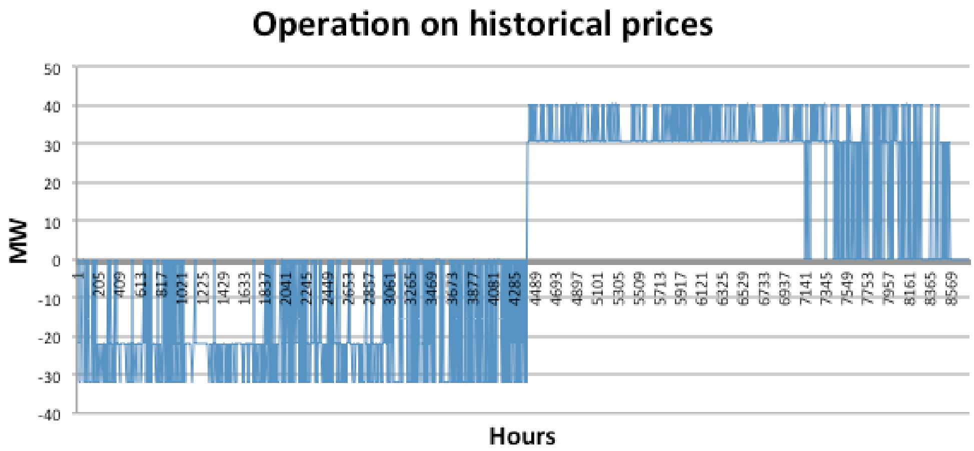

Figure 48 Operation on historical prices, Alternative 2

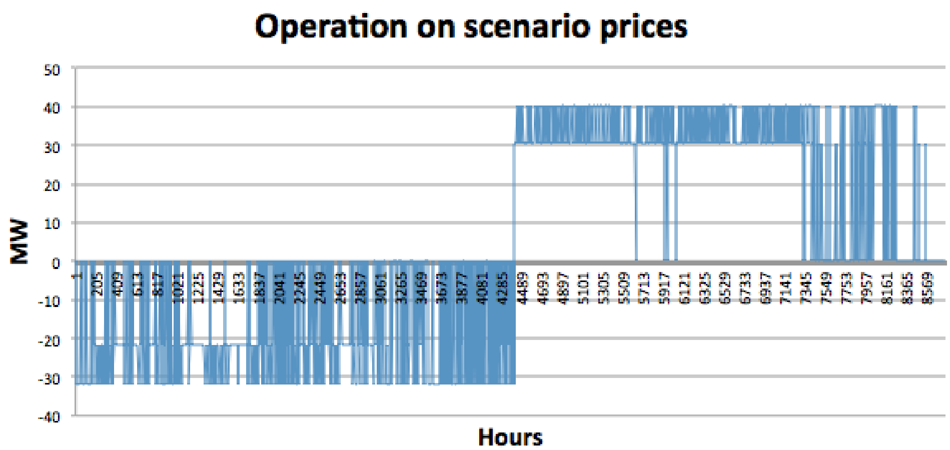

Figure 49 Operation on scenario prices, Alternative 2

The number of start/stops for the historical prices is 273 and 303 for scenario prices. That means that yearly variable cost are 273 000 NOK with simulation on historical prices and 303 000 NOK with simulation on scenario prices.

7.3 Alternative 3 – Fixed speed pump with increased flow capacity

An alternative with increased flow capacity is evaluated. Original maximum flow capacity in to the turbine is 15 m^3/sec whereas an alternative with flow capacity of 25 m^3/sec is evaluated. It is assumed that increased cost for bigger machine size and increased civil cost because of increase in tunnel cross-section and bigger powerhouse equal the total increase in investment cost. The cost estimation presented in the following does only cover the parts representing the highest increase in investment cost. For that reason, a buffer cost has been added to the total.

7.3.1 Civil costs

With increased flow the dimension of the water way has to be revaluated. An insufficient cross section will result in unnecessary head loss due to friction, and an over dimensioned cross section will lead to unnecessary high investment costs. The optimal cross section area of the waterway is based on an expectation of the value of power production. The optimal cross section is found when the marginal cost for increasing the cross section equals net present value of earned value. In this study there has not been performed an optimization of the cross section area. This is because the purpose of the study is to get a general insight in how increased flexibility of a power station increase income potential, rather than conduct a optimal detailed design. The increase in flow capacity does not result in increased power production, but raise the flexibility of the power station because operation can be concentrated in profitable hours. However, a set of assumptions is made in order to find a suitable cross section for the chosen capacity flow of 25 m^3/sec. In order to find suitable increase in tunnel dimension for alternative 3, the objective was to minimize the sum of increased civil costs and value of lost production due to head loss.

7.3.1.1 The water way

The head loss in the tunnel is calculated according to formula 9 and the head loss in the pressure shaft pipe is calculated with formula 10.

Head loss in the tunnel and in the steel lined pressure shaft is found for the “new” flow capacity from different cross sections. The head losses for the tunnel and the pressure shaft are used to calculate economic loss over the lifetime. The following assumptions are used:

- Average energy price 260 NOK/MWh
- 90% efficiency
- Operation time is 80% of the year (7008hours)
- Expected lifetime is 20 years
- Rate of return is 7%

The energy loss (E_{loss}) is then found for different cross sections

$$E_{loss} = Qgh\eta * 7008\ hours \tag{12}$$

To find the yearly economic loss the energy loss is multiplied with the average energy price

$$Economic\ loss = E_{loss} * 260\ NOK/MWh$$

The yearly economic loss for each cross section is then multiplied with the annuity factor to find the economic loss over the lifetime, present value of an annuity.

$$PV = \frac{1-(1+r)^{-n}}{r} \tag{13}$$

With the assumptions above the annuity factor is 10,6.

The cost for tunnel expansion can be found from NVE cost basis. By reading from figure B.4.1. a costs increase of 250 NOK/m2 seems like a reasonable assumption. As earlier mentioned, the objective is to minimize the sum of economic loss and tunnel costs. Figure 50 illustrates the variation in economic loss and investment cost with different cross section areas.

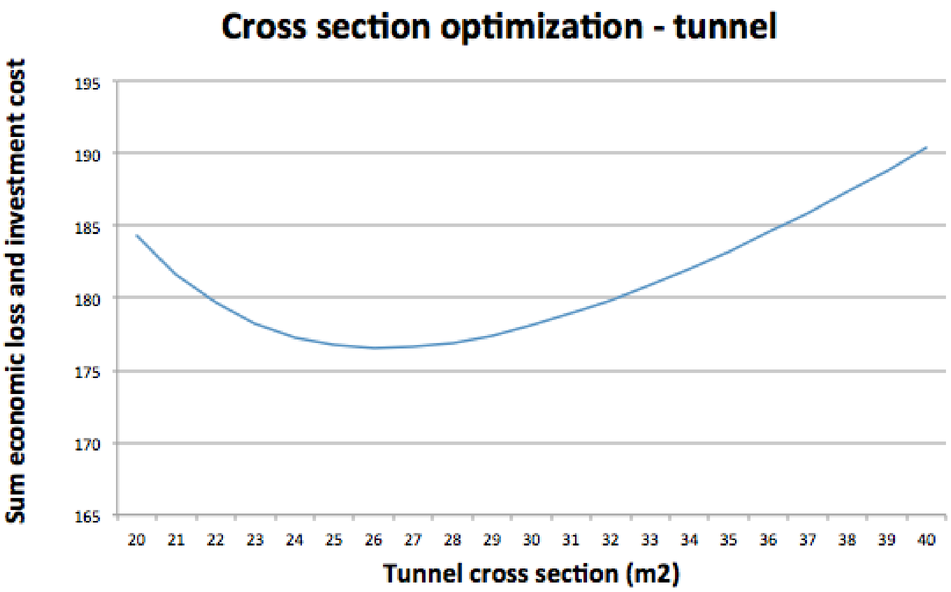

Figure 50 Cross section optimization of tunnel

The optimal cross section for the tunnel is 26m^2. This means an increase of 6m^2 from alternative 1. The cost basis indicates that he price is about 250 NOK per m^2 increase in cross section area. The tunnel is in total 7500m long, meaning the total increase in tunnel cost will be 11,25 mill NOK.

The optimization for the steel lined pressure shaft follows the same procedure as for the tunnel – the objective is to minimize the cost of investment cost and economic loss due to head loss. The cost for increased diameter of the steel lined pressure shaft is enhanced from the cost basis of NVE. Figure B.7.2. illustrates that the increase in price is about 10 000NOK per meter increase in diameter. The same assumptions for energy price and annuity factor are used as for the tunnel optimization.

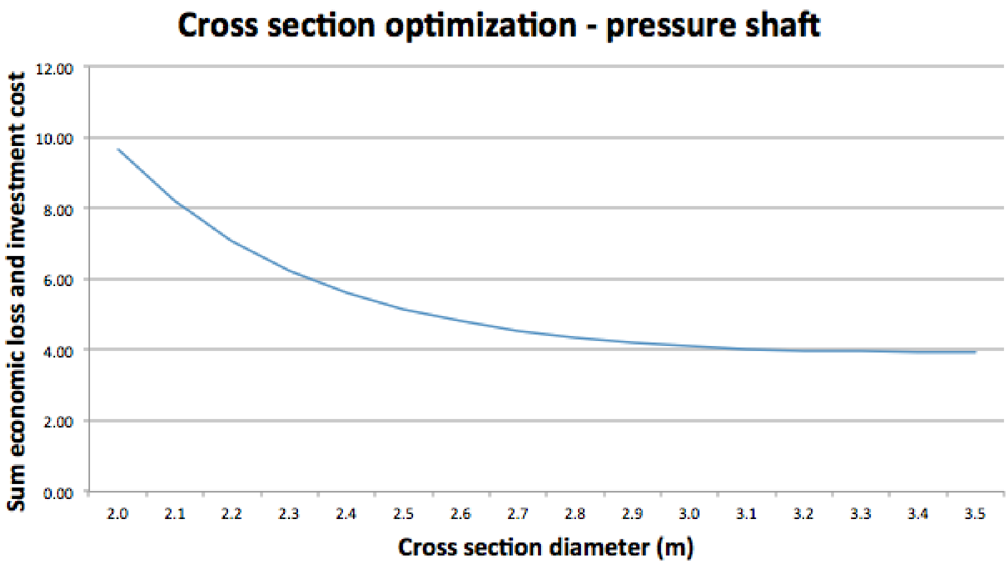

Figure 51 Cross section optimization of pressure shaft

The optimal pressure shaft diameter is then 3,4 m meaning about 1,4 m increase from alternative 1. The length of the pressure shaft is 50m, meaning the total increase in cost will be 700 000NOK

The total new head loss of the water way is then given by the sum of the head loss in the tunnel and the pressure shaft pipe and is 4,8m. For further calculations the head loss is rounded up to 5m.

7.3.1.2 Power station

Increased capacity will also result in the necessity of increased blasting volume for the power station. NVE has proposed the following formula for to necessary blasting volume for power stations in hard rock;

$$V = 78 * H^{0,5} * Q^{0,7} * n^{0,7} \tag{14}$$

The mean turbine height is 336m. With an assumed head loss of 5m and a turbine efficiency of 92%, the net height is then 304m. The net head from alternative 1 is 305, in other words a decrease of 1 m in net head. The number of aggregates is one. Increase from 15 m^3/sec to 25m^3/sec results in increase in volume of 3877 m^3.

Component	**Unit price**	**Increase compared to Alt. 1**	**Cost**
Blasting volume	230 kr/m3	3877 m3	891 710 NOK
Concrete volume (20% of blasted volume)	2500 kr/m3	775 m3	1 937 500 NOK
Reinforcement (60kg/m3 concrete)	16 000 kr/tons	46500 kg	744 000 NOK
Formwork (2,1m2/m3 concrete)	1000 kr/m2	1627 m2	1 627 000 NOK
Protection efforts	15% of blasting costs		133 756 NOK
Plasterwork	5% of the costs for blasting and concrete work		141 460 NOK
Interior	15% of the costs for blasting and concrete work		424 381 NOK
Unforeseen accidents	10% of all costs		589 980 NOK
Rigging and operation	25-30% of all costs		1 769 942 NOK
TOTAL			**8 259 729 NOK**

Table 24 Increase in costs for the power house Alternative 3

7.3.2 Mechanical cost

The installed capacity with a maximum flow of $25m^2$/sec the installed capacity of the turbine are calculated according of formula 11 and is 75 MW.

This is an increase of 27MW in the installed capacity. According to the cost basis from NVE, the ratio between ordinary Francis turbines and pump turbines are 1,25. The cost basis gives the turbine cost NOK/kW, as a function of maximum flow and head. For maximum flow of 25m3/sec and head of 330m, the cost is 520NOK/kW. Taken into account the ratio between ordinary turbine cost and pump turbine costs, the cost increase should be 650NOK/kW. The cost for the pump turbine of Alternative 1 is 35 mill NOK. With a total increase of 27MW, the increase in pump turbine cost is 17,55 mill NOK.

7.3.3 Electrical costs

The costs basis from NVE sums up the electro technical costs for power stations. The total cost per installed MW is given from different rotational speeds. The gradient of the cost curves are used to find the increase in cost corresponding to an increase of 20MW installed capacity. The electro technical costs increases about 500 000 for every increase in MW, in other words the increase in electro technical work will be 13,5 mill NOK. Hydro Energy has estimated that installation of a frequency converter will result in an extra 20 mill NOK in the investment cost.

7.3.4 Buffer costs

As an extra safety margin, a buffer cost has been added to the cost estimation. It is assumed that 120% of the calculated increases in investment cost represent acceptable cost estimation for alternative 3.

7.3.5 Summary of costs

Component	Increase in cost	Consumer price index	Resulting cost
Waterway	11 950 000NOK	7%	12 786 500 NOK
Power house	8 259 729 NOK	7%	8 837 910 NOK
Pump turbine	17 550 000	7%	18 778 500 NOK
Electro	13 500 000	7%	14 450 000 NOK
Frequency converter	20 000 000		20 000 000 NOK
Total increase			74 847 910 NOK
Buffer costs	20% of total increase		14 969 582 NOK
Original investment cost			609 900 000 NOK
Resulting investment costs			**699 717 000 NOK**

Table 25 Cost estimation Alternative 3

7.3.6 Operating and maintenance cost

In order to maximize income the operation plan over the year is as follows.

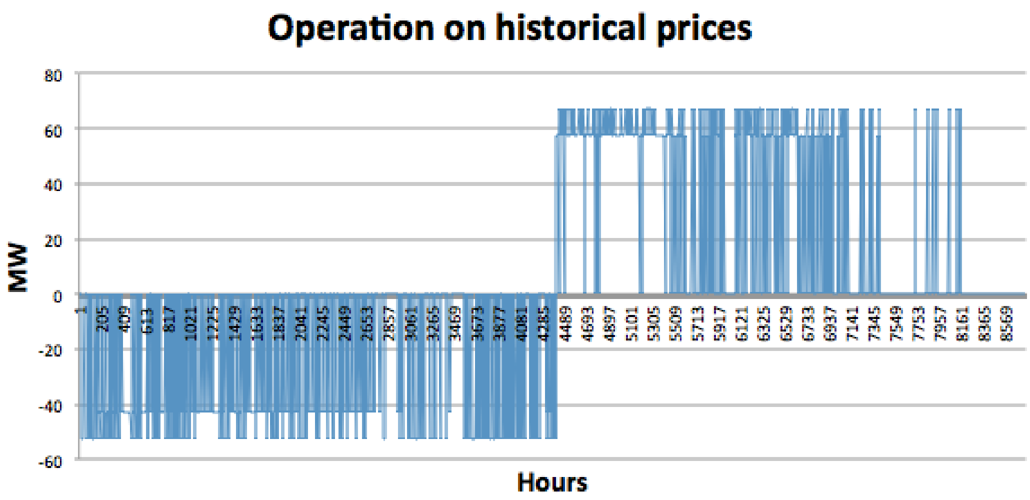

Figure 52 Operation on historical prices, Alternative 3

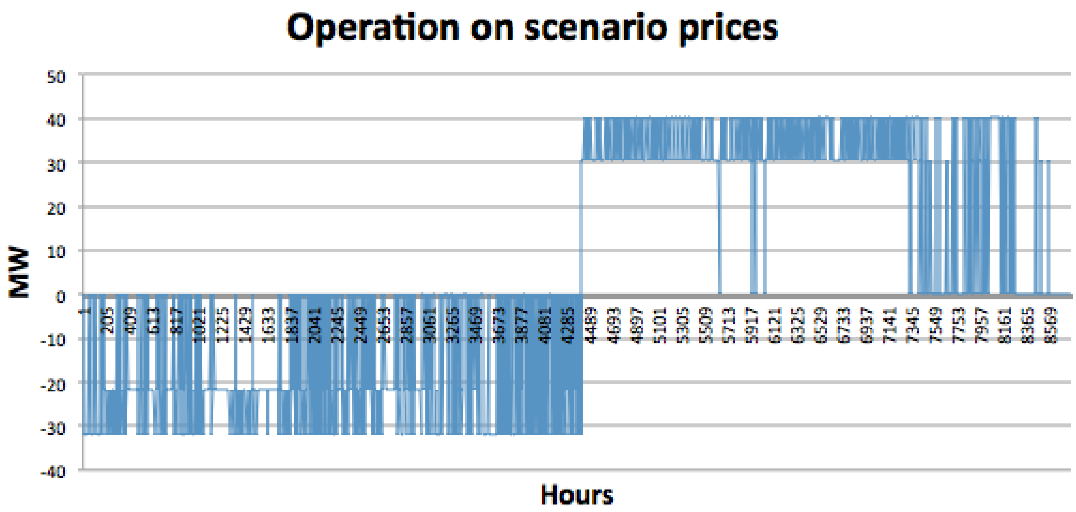

Figure 53 Operation on scenario prices, Alternative 3

The number of start/stops for the historical prices is 447 and 420 for scenario prices. That means that yearly variable cost are 447 000 NOK with simulation on historical prices and 420 000 NOK with simulation on scenario prices.

8 Investment analysis

8.1 Yearly net cash flow

The net yearly cash flow is the sum of income potential and yearly variable costs. Yearly income is calculated in chapter 6 and yearly variable cost are calculated in chapter 7.

The net yearly cash flows for historical prices are as follows:

	Percentage of potential income	**Income**	**Variable cost**	**Yearly cash flow**
Alternative 1	100%	38 720	69	**38 651**
	80%	30 976	69	**30 907**
	60%	23 232	69	**23 163**
Alternative 2	100%	61 155	273	**60 882**
	80%	48 924	273	**48 651**
	60%	36 693	273	**36 420**
Alternative 3	100%	65 455	447	**65 008**
	80%	52 364	447	**51 917**
	60%	39 273	447	**38 826**

*Table 26 Calculation of yearly cash flow for historical prices (*1000NOK)*

The net yearly cash flow for scenario prices are as follows

	Percentage of potential income	Income	Variable cost	Yearly cash flow
Alternative 1	100%	44 544	61	**44 483**
	80%	35 635	61	**35 574**
	60%	26 726	61	**26 665**
Alternative 2	100%	68 273	303	**67 970**
	80%	54 618	303	**54 315**
	60%	40 964	303	**40 661**
Alternative 3	100%	73 455	420	**73 035**
	80%	58 764	420	**58 344**
	60%	44 073	420	**43 653**

*Table 27 Calculation of yearly cash flow for scenario prices (*1000NOK)*

8.2 Net present value

Net present value method is used for measure profitability of hydropower development. The approach accounts for the time value of money. Money in the future has smaller value than the same amount of money today.

$$NPV = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} - C_0 \tag{15}$$

C_t is annual net cash flow in year t, C_0 is initial investment cost and r is the discount rate.

For an investment with assumed constant cash flow over the lifetime the NPV can be calculated as the following;

$$NPV = net\ annual\ revenue * \frac{1-(1+r)^{-t}}{r} - investment\ cost$$

The discount rate accounts for the time relevance for value of money, risk and alternative investments. If NPV is higher than 0, the project is profitable with the requested rate of return.

In this project constant cash flow throughout the lifetime is assumed. In real life, there will off course be variation between years, but since the lifetime of a hydropower project is so long, assuming a constant yearly cash flow may serve as a good indication.

The discount rate considered for investment analysis is 7%.

8.3 Results based on historical prices

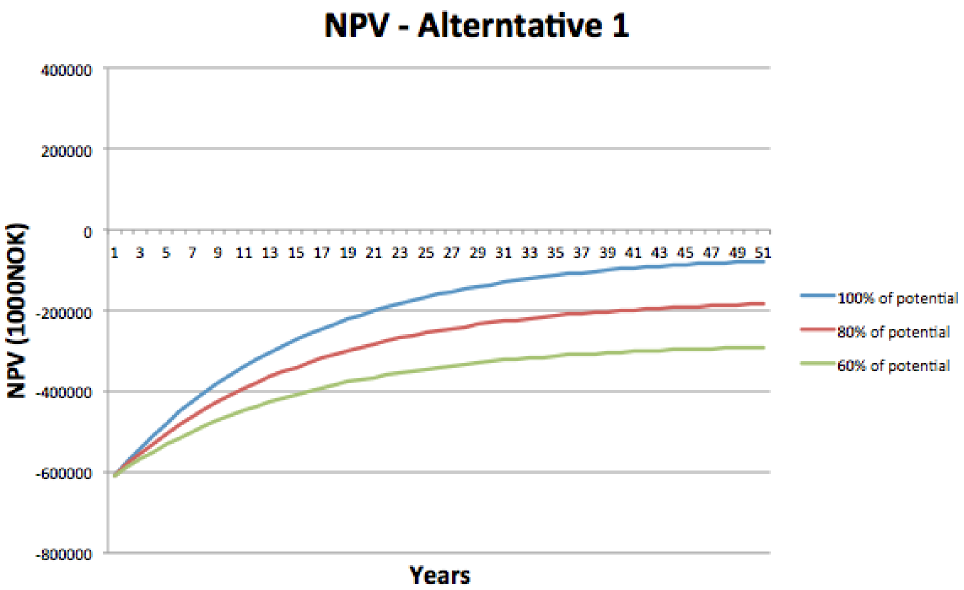

Figure 54 NPV of Alternative 1, income estimation based on historical prices

The net present value for Alternative 1 with income estimation based on historical prices never exceeds 0. This is a clear indication that the project is not profitable given the assumptions and preconditions for this report.

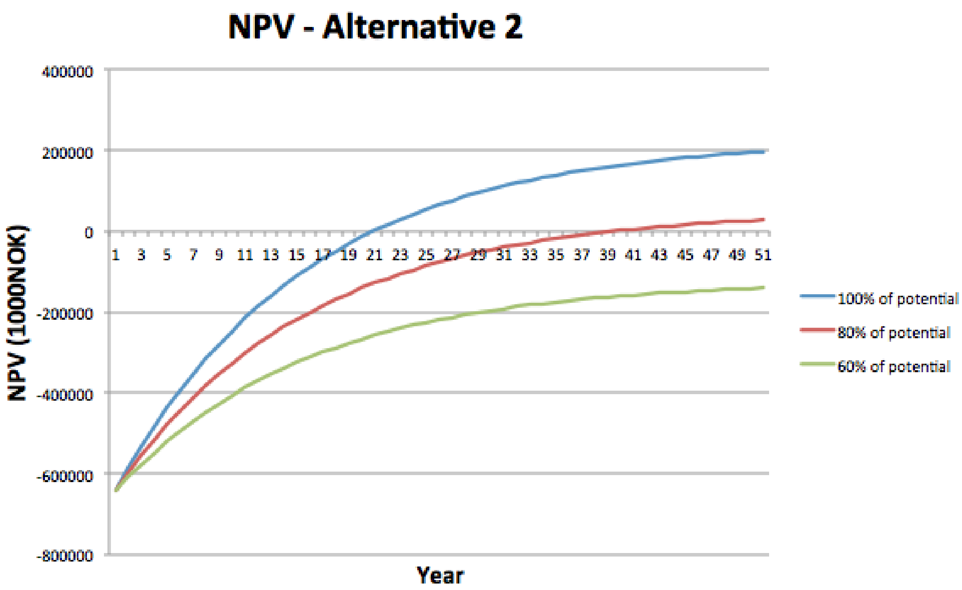

Figure 55 NPV of Alternative 2, income estimation based on historical prices

The net present value of Alternative 2 exceeds 0 after 19 years if 100% of the income potential is obtained. If 80% of the income potential is obtained the net present value exceeds 0 after 38 years. If 60% of the income potential is obtained the net present value will never exceed 0 during the estimated lifetime.

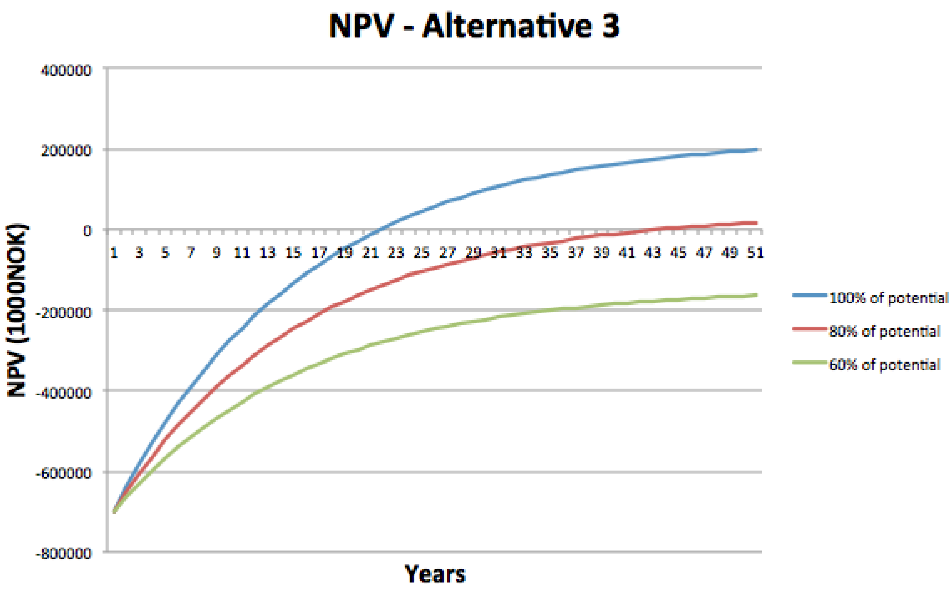

Figure 56 NPV of Alternative 3, income estimation based on historical prices

The net present value of Alternative 3 exceeds 0 after 20 years if 100% of the income potential is obtained. If 80% of the income potential is obtained the net present value exceeds 0 after 42 years. With 60% of the income potential the net present value never exceeds 0.

8.4 Results based on scenario prices

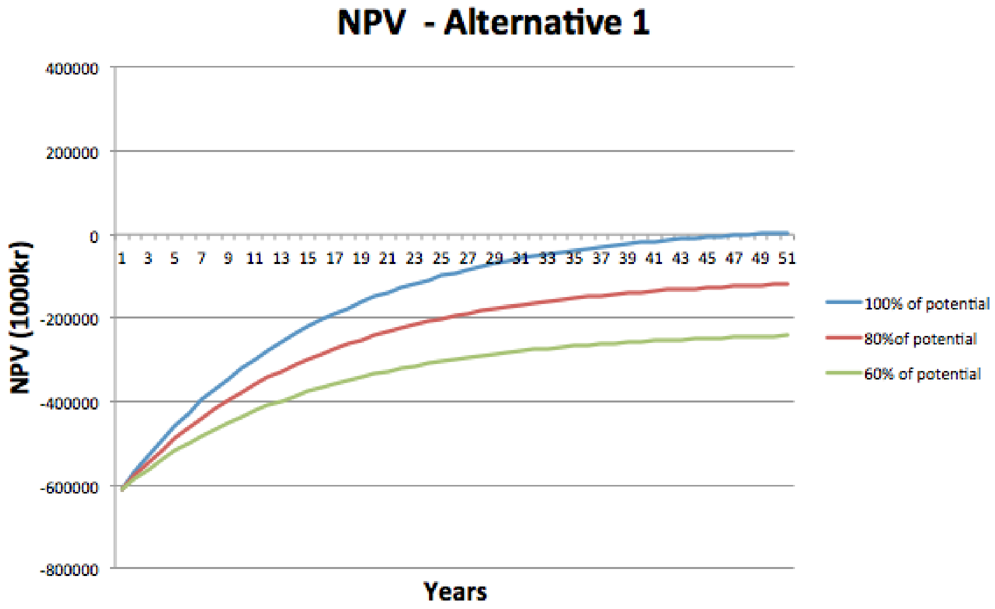

Figure 57 NPV of Alternative 1, income estimation based on scenario prices

The net present value exceeds 0 during the lifetime of the project only if 100% of the income potential is obtained when income is estimated with scenario prices. Net present value will then exceed 0 after 47 years.

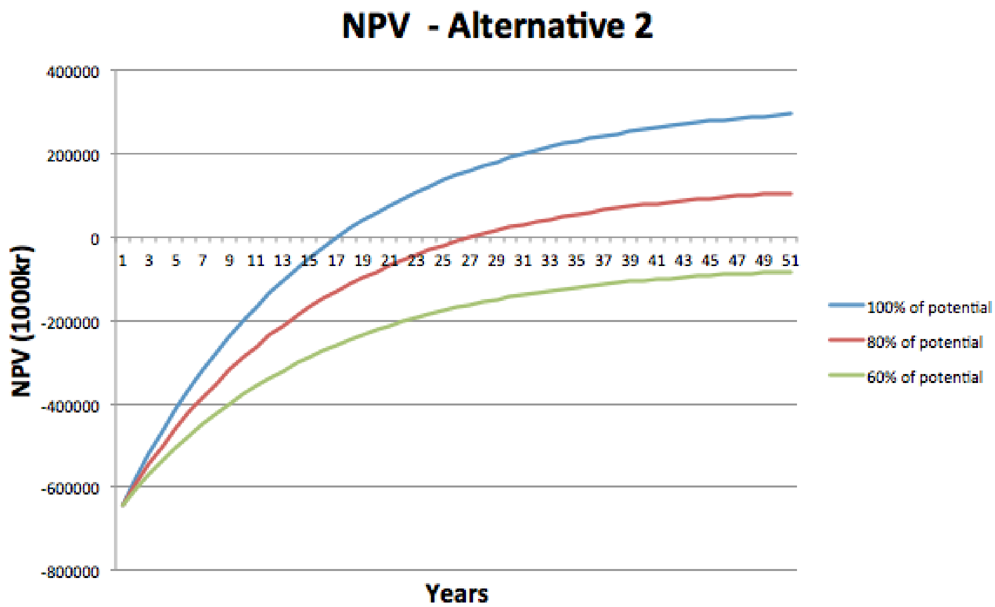

Figure 58 NPV of Alternative 2, income estimation based on scenario prices

The net present value of Alternative 2 exceeds 0 after 17 years when 100% of the income potential is obtained. If 80% of the income potential is obtained net present value exceeds 0 after 26 years.

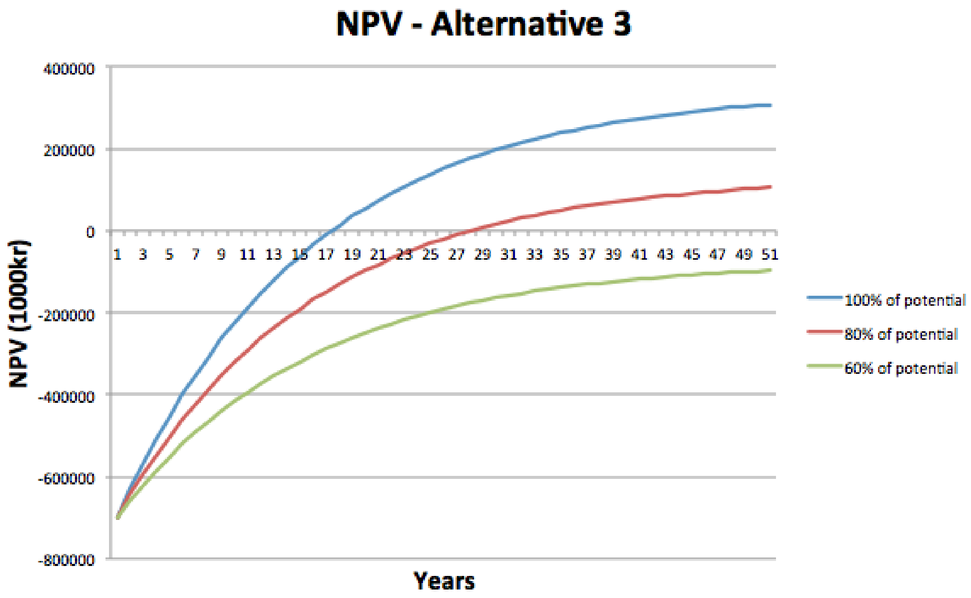

Figure 59 NPV of Alternative 3, income estimation based on scenario prices

The net present value of Alternative 3 exceeds 0 after 16 years when 100% of the income potential is obtained. If 80% of the income potential is obtained net present value exceeds 0 after 28 years.

9 Discussion

This chapter contains evaluation of the economic feasibility of the alternatives presented. Assumptions and methods done in the study are also discussed.

9.1 Evaluation of economically feasibility of the alternatives

Alternative 1 is not considered profitable with income estimate based on historical prices or with income estimate based on scenario prices. Alternative 2 is considered profitable when income is between 80 and 100% of potential. This goes for both the estimate based on historical prices and for the estimate based on scenario prices. The net present value will exceed 0 faster when income is simulated with scenario prices and obtain a higher net present value at the end of the project lifetime of 50 years. The investment analysis of Alternative 3 shows very similar behavior as Alternative 2. The project is profitable when income is between 80 and 100% of potential and profitability has greater potential when simulated on price scenario.

The increase in potential income for systems with a variable speed pump shows to be present. This is because pumping operation has the potential to cause positive income with participating in the RK down regulating market. When supply exceeds demand in the grid, the system operator will pay market participants to increase consumption on order to maintain balance if supply and demand. This is, as mentioned, advantageous for a pump storage plant and can lead to increase in net income. However, as market structure is today, this earning strategy is associated with risk as bids in the market not necessarily are expected.

9.2 Assumptions and methods

The conclusions on profitability for the different technical alternatives do heavily depend on the assumptions made. Regardless of this, the results of the report may contribute to give a indication on the income potential when considering balancing and ancillary service markets. In the following, the most influential factors are discussed.

9.2.1 Hydrology

Power plant operation and income estimation are based on hydrologic data and prices for one year. The period chosen for simulation are May 2013 to April 2014. Runoff data shows that inflow in 2013 where unusual high. This may lead to an overestimation of production. The prices are affected by inflow and high inflow is often causing lower prices. Therefore, to say whether income is overestimated or underestimated are hence not unambiguously.

9.2.2 Estimation of production

The evaluation of average “new” production after project realization is done in chapter 6.5 and is calculated to be 63,3 GWh on a yearly basis. This is far below previous estimates done in pre study reports for the project. The permission application indicates an increase in production of 112 GWh. The main reason for this might be that flood loss below Fivlemyr reservoir and in Illvatn is not taken into account for the zero-alternative. As of today, there are difficulties related to keeping water levels Skålavatn low enough to avoid flood loss. Realization of Illvtan pump storage power plant will lead to increased storing possibilities of the inflow to Fivlemyr and Illvatn and thereby contribute to decrease in flood loss for the whole system, especially “Sydoverføringen”. It is likely that the estimated increase in production, and thereby also increase in income, is underestimated.

9.2.3 Market prices and market design

Yearly cash flow for the repayment period is assumed to be constant. This is off course not the case in real life, where both hydrology and prices can vary greatly from year to year. However, because of the nature of hydropower projects with a long lifetime, a yearly average of the income is assumed.

An assumption affecting the profitability is the price scenario. If higher prices are expected, profitability of the project will also increase. Market prices to be seen during the lifetime of a hydropower project are linked to great uncertainty. Major changes in the power market are described in Chapter 2. It is not unimaginable that delivering of balancing energy and ancillary services will be even more profitable than estimated in this report.

The spot market, primary reserves and tertiary reserves are considered for simulation and income estimation. In a real situation, more markets are considered. Consideration of more markets could potentially lead to higher income potential

Income from “green certificates” is not taken into account in this project. “Green certificates” is a market based support scheme to support new power generation from renewable energy sources developed before 2020 (https://www.regjeringen.no/en/topics/energy/fornybar-energi/electricity-certificates/id517462/). In case of project completion before 2020 income from “green certificates” may make the project more profitable.

Finally, operation simulation and income estimation is done under the assumption of an unchanged market design. The impending challenges with respect to maintain energy balance and grid security may lead to changes in market design like smaller timescales for the spot market. This amendment is not taken into consideration.

9.2.4 Power plant operation

Operation of the pump storage plant is assumed static, with pumping in the summer months and production in the winter period. This is to maximize total production. In reality, the operation is likely to be more dynamic with both production and pumping operation all year. Especially for Alternative 3, limiting production to the winter period and pumping to the summer period may limit the income potential.

Little flexibility in terms of load variation is assumed for simulation in order to take advantage of hours with price drops and peaks. This will, as shown in the graphs for power plant operation, lead to many starts and stops. The operation is not optimized for variable costs due to rapid start and stops and income by flexible operation.

9.3 Environmental impact of project realization

NVE express concerns regarding increased regulating of reservoirs as a consequence of the pump storage project in the recommendation to NVE. As a mitigation measure, NVE has purposed restrictions on operation. Production between Illvatn and Fivlemyr is not allowed between 1st of July and 15th of September when water level in Illvatn is below a certain level. Simulations on power plant operation are consistent with these requirements.

Alternative 3 presented in this study, with increased flow capacity, will have a greater negative environmental impact in the construction period than Alternative 1 and 2 because of increased tunneling. Also during the operating period, the environmental consequences will be more apparent.

10 Conclusion

This chapter contains final recommendation for investment decision of Illvatn pump storage project based on the method and assumptions in this study.

10.1 Recommendations

The ongoing changes in the power market would potentially be a “game changer” in order to quantify profitability for pump storage hydropower in Norway and should be considered for investment decisions. Increased demand for balancing energy and ancillary services may lead to changed operation principles of the power plant. Not least, consideration of balancing markets and ancillary service markets for income estimation and profitability analysis are likely to lead to higher income potential. However, investment decisions that are depended on income from balancing energy and ancillary services are linked to great risk. This is mostly due to uncertainty regarding market design and market prices. A well-functioning market should provide long-term price signals for investment purposes.

Alternative 2 is considered as the best alternative for Illvatn pump storage project. This solution includes a variable speed pump able to participate in balancing energy markets and ancillary service markets during pumping operation which can increase income potential compared to a pump with fixed speed (Alternative 1). Alternative 2 has a pumping capacity of 39MW and a production capacity of 45MW. If 80 to 100% of the income potential is obtained the net present value of the project will be 0 after 17-26 years. After a lifetime of 50 years, the net present value will be between 100 mill NOK and 300 mill NOK with scenario prices (assuming a discount rent of 7%). Because of the nature of Fortun power system, pumping operation between Fivlemyr and Illvatn proves to be very convenient. The energy equivalent for pumping from Fivlemyr to Illvatn is 1 kWh/m^3. The water available for production in Illvatn has a energy equivalent of 3,22kWh/m^3.

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