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Analysis of the new Market Simulator ProdMarket in the future Norwegian Power System

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Abstract

The main objective of this thesis has been to verify ProdMarket as a software tool. Three simulation cases is created to perform a future scenario analysis assessing ProdMarket's robustness and future potential. Overall, ProdMarket shows unsatisfactory economic results for systems with high penetration of intermittent power generation. Simulations are performed on a small-scale model of the Norwegian power system. A simplified implementation of continental transfer capacity is used to explore the impacts of increased cross-county interconnectivity. Balancing of intermittent power is of particular interest. Results have been compared to a second scheduling software, EMPS.

Facing increased integration and complexity, system operators and market participants are continually in need of better decision support tools to aid them in their search for effective operation and planning. ProdMarket is a state-of-the-art SINTEF-developed prototype in this search for efficiency. It uses stochastic dual-dynamic programming (SDDP) to simulate hydropower systems in great detail.

For the most part, results seem reasonable. ProdMarket shows superior utilization of the balancing capacity of conventional and pumped hydro power plants, leading to smaller short-term price oscillations. Results for the simulation case representing the present Norwegian system is very good. But ProdMarket shows unacceptably poor economic results relative to EMPS as parameters are changed in the two future scenarios.

Previous work with ProdMarket has shown good results when intermittent power is placed on the local level; poor results are now seen as intermittency is increased on the global level. The *price model* handles interaction between the local and global simulation modules in ProdMarket – it is suggested as a contributor to the poor economic results. The most obvious flaw in the results is that ProdMarket stores excessive amounts of water in hydropower magazines towards the end of the simulation period. This is attributed to weaknesses in using EOPS for internal end-of-period water valuation. End valuation is considered a second contributing factor to weak economic results in the future simulation cases.

Assessing the economic loss suffered as a results of each of the two problem factors presented is challenging. As a consequence, there is a great deal of uncertainty related to ProdMarket's future potential. Considerable improvements will have to be made on the model's robustness in order for ProdMarket to become a serious alternative to models such as the EMPS.

Sammendrag

Hovedmålet med denne studien har vært å verifisere planleggings-verktøyet ProdMarket. Tre simuleringscase har blitt brukt for å utføre en scenarioanalyse hvor ProdMarkets robusthet og fremtidige potensiale har blitt vurdert. ProdMarket viser ikke tilfredsstillende økonomiske resultater for systemer med høy andel uregulerbar kraft. Simuleringer har blitt gjort på en småskala modell av det norske kraftsystemet. En forenklet implementering av kontinental overføringskapasitet har blitt brukt til å undersøke effektene av økt krafthandel på tvers av landegrenser. Balansering av uregulerbar kraft har vært av særlig interesse. Resultatene har blitt sammenlignet med det eksisterende analyseverktøyet EMPS (Samkjøringsmodellen).

I møte med økt kompleksitet og integrasjon stilles det stadig større krav til beslutningsstøtte-verktøy blant systemoperatører og markedsaktører. ProdMarket er en SINTEF-utviklet prototype som utnytter stokastisk dual-dynamisk programmering (SDDP) for å simulere vannkraftsystemer i stor detalj.

Stort sett gir ProdMarket realistiske og fornuftige resultater. ProdMarket viser overlegen evne til balansering ved bruk av både konvensjonell vannkraft og pumpekraft, noe som fører til en reduksjon i kortsiktige prissvingninger. Resultatene fra simuleringen av det nåværende norske vannkraftsystemet er svært gode. Derimot viser ProdMarket svært dårlige økonomiske resultater for de to fremtidige scenarioene hvor faktorer som andel uregulerbar kraft er økt.

Tidligere studier av ProdMarket har vist gode resultater når uregulerbar kraft plasseres på lokalt nivå; denne studien viser imidlertid dårlige resultater når dette gjøres på globalt nivå. Prismodellen håndterer interaksjonen mellom de lokale og globale simuleringsmodulene i ProdMarket – det er derfor trolig at den bidrar til de dårlige økonomiske resultatene. Den eneste åpenbare feilen i resultatene er at ProdMarket lagrer overdrevent store mengder vann i vannkraftmagasinene mot slutten av simuleringsperioden. Dette tilskrives svakheter ved å bruke EOPS i den interne sluttverdisettingen.

En vurdering av de økonomiske tapene for hvert av de identifiserte problemfaktorene er krevende. Som en konsekvens av dette er det knyttet stor usikkerhet til ProdMarkets fremtidige potensiale som beslutningsstøtteverktøy. Betydelige forbedringer må gjøres med modellens robusthet for at ProdMarket skal kunne bli et alternativ til eksisterende modeller som EMPS.

Preface

This document constitutes a master's thesis written in relation to the subject "TET4915 Energiplanlegging og miljøanalyse, masteroppgave" at NTNU. It mainly discusses simulation results from the hydropower scheduling tool ProdMarket, as well as results from EMPS which is used for comparison. The objective is to analyse ProdMarket's performance in the power market of today and of the future.

EOPS has been used as a stepping stone into the rather basic-looking user interfaces that still dazzle the world of hydropower scheduling software – perhaps someday the revolution in user friendliness that has long since changed consumer industries will reach this industry as well…

The work performed is largely a continuation of the project thesis from "TET4530 Energiplanlegging og miljøanalyse, fordypningsprosjekt" from the fall semester of 2015. Hence some sections of this thesis builds upon the project thesis. Unlike the project thesis, I have chosen to use the English names of the EOPS and EMPS models in this text, instead of the Norwegian names "Vansimtap" and "Samkjøringsmodellen".

The formatting of the thesis is based on advice from a formatting guide by NTNU's Orakeltjenesten (2013). Some effort has been put into keeping a consequent APA 6th-style referencing throughout the thesis. The APA style has been chosen over alternative methods as I find it better acknowledges referenced material in larger written works like this thesis.

I would like to thank my supervisors Magnus Korpås and Arild Lote Henden for their guidance. Arild's day-to-day help and knowledge of the two models used have been of utmost importance to the progress of this thesis.

Trondheim, 24.06.2016

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Problem description

Developed in cooperation with supervisors Magnus Korpås (NTNU) and Arild Lote Henden (SINTEF).

The Norwegian and European power systems are constantly changing. The energy system of the future will include large amounts of renewable energies and there will be more cross-country power trade. This leads to a need for improved analytical tools. SINTEF Energi is currently developing a new simulation software based on the existing model ProdRisk. ProdRisk is a stochastic optimization model and is widely used among Norwegian hydro power producers. The new prototype, ProdMarket, runs ProdRisk on its sub-areas, forming a strategy for water usage. It then performs a detailed system-wide simulation based on this strategy. Since the model is under development, feedback will contribute to its development and improved realism.

The aim of the work is to verify how ProdMarket handles the future's energy system on a simplified Norwegian data set. This is to be done through adjusting the penetration of renewable power and pumped storage in the system. Since ProdMarket is a prototype, it must be verified by comparison to an established model (EMPS) and to theory in terms of results and convergence-characteristics. Results should be studied in detail, ranging from a weekly resolution to overall results such as economic results and power prices.

The first part of the task is to develop a data set for testing of ProdMarket. The data set will be based on an existing test data set, but should be expanded upon to provide a good model of the present Norwegian system. Subsequently, the data set is to be modified to represent a future system with higher cross-country integration and more renewable power.

Oppgave

Utviklet i samarbeid med veiledere Magnus Korpås (NTN) og Arild Lote Henden (SINTEF).

Det er planlagt store endringer i kraftsystemet i Norge og Europa, og endringene skjer raskt. Fremtidens kraftsystem vil inneholde store mengder fornybarenergi, det vil være mer handel på tvers av land. Dette fører til at bedre analysemodeller må utvikles. SINTEF Energi utvikler nå en ny beregningsmodell/-metode basert på den etablerte modellen ProdRisk. ProdRisk er en stokastisk optimeringsmodell og blir nytt av mange av de nordiske vannkraftprodusentene. Den nye prototypmodellen, ProdMarket, kjører ProdRisk på del-nivå (vassdrag eller delområde) for å danne en strategi for bruk av vannet. På systemnivået kjøres en detaljert simulering med strategien fra delnivået. Siden modellen er i utvikling vil studenten kunne bidra til at den blir bedre og mer virkelighetstro.

Målet til oppgaven er å kontrollere hvordan ProdMarket takler fremtidens energisystem på et forenklet Norge-datasett. Dette ved å endre andel fornybarenergi og pumpekraft som er i systemet. Siden ProdMarket er en testversjon må den kontrolleres i forhold til etablerte modeller (EMPS) og teori med tanke på resultat og konvergens-egenskaper. Resultatene bør kontrolleres i detalj for enkelt-uker til overordna resultat som økonomi, kraftverdier.

Første del av oppgaven består i å etablere testdatasett for testing av ProdMarket. Datasettet kan baseres på et eksisterende testdatasett, men det skal utvides slik at det gir god men enkel modell av dagens norske system. Videre skal datasettet videreutvikles slik at det representerer et tenkt fremtidssystem som med mer tilknytning mellom land og med mer fornybar kraft.

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Abbreviations

CCS	Carbon Capture and Storage
EMPS	EFI’s Multi-area Power Scheduling model. The Norwegian name is “Samkjøringsmodellen”.
EOPS	EFI’s One-area Power Scheduling model. The Norwegian name is “Vansimtap”.
HSPP	Hydro Storage Power Plant. Hydropower with storage reservoir, but without pump capacity.
HVDC	High Voltage Direct Current
NVE	Norges vassdrags- og energidirektorat (Norwegian Water Resources and Energy Directorate)
PHES	Pumped Hydro-Electric Storage
PM	ProdMarket.
PSPP	Pumped Storage Power Plant. Synonym to PHES plant.
PV	Photo-Voltaic. The technology behind solar panels and solar power.
RES	Renewable Energy Sources
RoR	Run-of-River hydropower
SDDP	Stochastic Dual Dynamic Programming
SDP	Stochastic Dynamic Programming
SSB	“Statistisk Sentralbyrå”, Norway's central institution for producing official statistics.
VRES	Variable RES.
WV	Water Value

Nomenclature

Cuts	Linearized curves (surfaces) describing future cost function (water value function) of reservoir(-s).
Firm demand	Demand that is modelled as price inelastic, “must” be met.
Guideline curve	Describe sum production level for aggregated system, as calculated in the first step of EOPS’s simulation part. Norwegian: “Styrekurve”.
Load period	Periods that define load levels that each represent a given number of hours of the week.
Price model	The price model defines the probabilities of moving from each price point in one period to each new price point in the next period.
Price period	Used instead of “load period” as generation as well as load is varied between each period in EMPS and PM.
Price series	A series of power prices representing each week and price period in the simulation period.
Transfer series	Time series that mimics the positive and negative flow on an interconnector; calculated as: $Production - load = transfer$.

Chapter 1 Introduction

The power system is constantly changing as it adapts to real-time and long term load and generation trends. The common denominator as times pass is that the system as a whole is headed towards a more complex state. In this world of increased integration, system operators and market participants are continually in need of better decision support tools to aid them in their search for effective operation and planning. ProdMarket is a state-of-the-art SINTEF-developed prototype in this search for efficiency. It is based on an idea of mimicking a power market where multiple participants strive to maximize their own profit. It uses an existing model, ProdRisk, to simulate each participant's decisions. Building on this powerful local modelling tool, ProdMarket expands its reach into larger-scale problems while maintaining model detail and accuracy.

This thesis applies ProdMarket to solve a hydro planning problem. Early tests (Henden, 2015b; Kyllingstad, 2015) have showed encouraging results on water handling and use of pumped storage in systems with considerable amounts of intermittent power. This thesis further explores and challenges ProdMarket along similar axes.

A data set based on the present Norwegian power system is used as a Base case. The simulated system has three waterways and is simulated over a three-year period. An updated version of ProdMarket allows for including wind and solar power generation in the data set. Moreover, simulated time resolution is increased compared to previous work, highlighting short-term price fluctuations. Subsequently, two future scenarios are created to simulate possible future trends affecting the Norwegian power system. Increased penetration of intermittent power, both in Norway and in surrounding countries, is a main focal point. A simplified implementation of continental transfer capacity is used to explore the impacts of increased cross-county interconnectivity to countries with large-scale development of new renewable energy. Balancing of the intermittent power using production regulation and large-scale pumped hydroelectric storage is of particular interest.

Results are compared to the EMPS model, a tried-and-true simulation model of widespread use.

1.1 Scope of work

The main objective of this thesis is to verify ProdMarket as a software tool. This is done through a series of simulations on a small-scale model of the Norwegian power system. Combined, the simulation cases constitute a future scenario analysis assessing ProdMarket's robustness and future potential. Moreover, analysing ProdMarket means comparing it to a second scheduling model, EMPS.

Based on a preceding discussion of their theoretical and mathematical basis, the two hydro-planning models are presented in detail before running simulations. Subsequently, the methodology of creating the three simulation cases is comprehensively documented. Finally, simulation results are presented and discussed.

1.2 Limitations

Throughout this thesis many of the numbers will be based on the Norwegian and European hydropower systems and possible future trends. The intention is that the simulation cases studied will hold a level of realism that allows for insights into production planning of the full-scale Norwegian system. Nonetheless, the main focus remains to compare the software models EMPS and ProdMarket, not on predicting the future topology of the Norwegian power system. As such, the analysis strives to exercise the required circumspection in expanding on the results into possible real-life implications.

The EMPS model is chosen as a "benchmark" for comparison due to its widespread use and robustness in terms of results. ProdMarket is still a prototype, so it suffers some limitations compared to EMPS. For example, ProdMarket does not yet support limited transfer capacities between multiple power areas, as EMPS does. Wind and solar power is also implemented in a relatively rudimental way. The idea behind ProdMarket is, however, that it will in the future solve the same multi-area problems as EMPS does today.

The energy system in general, and the power system in particular, is immensely complex. This thesis covers only a narrow band of present and future factors that has the capacity to make an impact on how the system behaves; the simulation cases studied are mainly differentiated along the following axes:

- Hydropower **production capacity**
- **Pumped hydroelectric storage** (PHES)
- **Demand** level in Norway

- **Wind** power in Norway
- Size of **interconnectors** to UK and Germany
    - UK **offshore wind** and demand levels to match interconnection
    - German **solar power** and demand levels to match interconnection

Integration with UK and Germany are picked among a long list of relevant countries as there are ongoing projects to build large HVDC interconnection links to each of the two.

1.3 SINTEF non-published material

Because ProdMarket and other models applied in this thesis stem from internal projects at SINTEF, much of the know-how of these models are confined to in-house knowledge. As a result, some sections of this thesis builds largely on discussions and interviews performed in person or via e-mail with co-supervisor Arild Lote Henden at SINTEF. This is particularly relevant for information regarding ProdMarket, which is still a prototype.

A large bulk of information on the models comes from internal SINTEF documents. For ProdMarket, Henden's (2015b) project report represents the only available written information about the model. SINTEF's user-manuals (n.d.-a, n.d.-b) have been a vital source for information on using and understanding the EOPS and EMPS models.

Chapter 2 Background: The power system

In a global setting, the Nordic countries, Norway in particular, is in a very special situation. For the past few generations, vast reservoirs have supplied society with enormous quantities of cheap electric power, fuelling growth in industries and society. This chapter will discuss some of the particulars of today's and tomorrow's Norwegian and European power system.

2.1 Present situation

Norway is dominated by large-scale hydropower production. The system has significant magazine capacity, some reservoirs storing several years' worth of inflow. Operation of this system will be tackled in the next chapter; here, we will focus on presenting a few of the most important characteristics of the overall power system.

Data on the Norwegian power system's production was collected from SSB's online statistics database (2015, n.d.-b). To even out the significant yearly variations, a linear regression analysis was performed on the numbers. The regression showed a mean annual total power production anno 2014 of roughly 138 TWh, of which 130 TWh was hydropower. Estimated load level was roughly 130 TWh, matching the calculated net export of almost 8 TWh. Due to the large yearly variations, accurately quantifying the Norwegian power system is not straight forward. We will come back to the accuracy of these numbers as we try to quantify the simulation scenarios in Section 5.3. A summary of the regression analysis is shown in Appendix C. The results indicate an estimated power mix as shown in the table below. Note that only hydro-, thermal- and wind-power is included in SSB's statistics, as these are the main technologies in Norway today.

Table 1 – Norwegian power mix 2014. Based on regression analysis.

Energy source	Percentage of production
Hydro	95.29
Thermal	3.36
Wind	1.36
Total	100.01

2.2 Future trends

2.2.1 Climate change and renewables

Moving forward, there are reasons to believe that Norway, as well as other Nordic and European countries, will further increase their energy surplus. And most of the reasons are either directly or indirectly related to climate change. The direct correlations were studied in a report by NVE on how climate change could affect the power-system in the long run. Amongst a long list of conclusions, it notes a couple of interesting aspects regarding inflow to the Norwegian hydro system: Seasonal variations are likely to decrease as temperatures rise and less precipitation fall as snow, and overall increased precipitation is likely to lead to increased overall production (NVE, 2010). As for indirect impacts of climate change, it is perhaps the effort made to avoid it which will have the strongest impacts; the very fundamentals of energy use and power systems are "X-rayed" in a search for "greener" solutions. And the solutions are plentiful: Countless ideas for smarter harvesting, transport, storage and use of electric and other energy are being tested and implemented. And crucially, there seems to be genuine political will behind efforts to guide the ongoing energy evolution.

Norway and Sweden's joint El-certificate programme (also called green certificates) set out to increase the combined system's renewable energy production capacity by up to 26.4 TWh by 2020 (Regjeringen.no, 2014); the final deadline for production start has since been extended to 2021 (Olje- og energidepatementet, 2015, p. 3). As of quarter one, 2016, NVE (2016) reports that 15.5 TWh of this production have already been built, with additional 6TWh under construction. The Nordic countries as well as the rest of the European Union have also agreed on the "20-20-20" climate and energy package. By 2020, it aims for 20 % decrease in greenhouse gas emissions compared to 1990-levels, 20 % decrease in demand by increasing energy efficiency and 20 % share of renewable energy sources in power generation (European

Commission, 2015). These goals have even been extended towards 2030, increasing renewable generation to a minimum of 27% of European Union energy use and to improving energy efficiency by 27% (European Environmental Agency, 2015). Statnett (2015a, p. 47) has estimated what this means for the power sector: A 40 to 50 percent decrease in emissions compared to 2005 levels, and almost 50 percent renewable production by 2030. These policies are testimonials that renewable production is here for the long haul – the following subsections will continue to explore this subject.

2.2.2 Intermittency

Most of the up-and-coming “green energy” technologies based on renewable resources share one crucial property; they are intermittent. This means that almost all countries planning large-scale shifts in their power industry towards renewables face similar challenges, whether it is wind, run-of-river hydro or solar energy production that replaces (or complements) the conventional technologies. As countries rely more heavily on renewable sources to cover their energy needs, the question is: What happens when the sun stops shining, the wind stops blowing or the river stops flowing? Whereas the power outputs from conventional thermal or hydropower production have been relatively easy to regulate, the new technologies offer limited to no such control. Several solutions to this challenge has been proposed; most work along one of the following axes: Making real-time consumption match production levels more closely, or storing excess energy for when production levels decrease. In practice, a combination of both approaches seems most likely. Matching consumption to production can be achieved by making the load more price elastic, i.e. more susceptible to price variations. This works because prices will drop when there is excess production, and rise when demand exceeds supply. One way of achieving better price elasticity is by giving consumers real-time price updates, allowing them to adjust their usage accordingly. Going down the alley of energy storage, this can be achieved in numerous ways; kinetic, potential and chemical energy storage schemes have all been suggested. This thesis looks at pumped hydropower as a way of storing potential energy in water.

2.2.3 Increased interconnection

Parallel to the shift towards more renewable energy production, the European power grid moves towards stronger interconnection between countries and markets. Statnett has estimated that the sum cross-border capacity between Norway and surround countries will double from about 5 GW in 2015 to roughly 10 GW in 2025. The Nordic countries (Norway, Sweden, Finland and parts of Denmark) are already connected as a single-area synchronous power system (NVE, 2015b). This thesis considers Norway's connection to the European mainland, which happens through subsea HVDC cables. Connection to Denmark is the strongest, with the fourth cable project named "Skagerrak 4" completed in 2014, increasing capacity by 700 MW (Statnett, 2015b, p. 7). In the coming years, two 1400 MW interconnectors are planned to Germany and England, respectively (Statnett, 2015b, p. 7). These are the interconnectors that have inspired the interconnected scenarios of this thesis.

Increased interconnection is not only about increasing physical power flow capacities on cross-country links: The financial implementation of the physical capacity into the system is of crucial importance. Considerable steps have been taken by The European Commission to secure "efficient use of cross-border capacity (…)" (Nord Pool, n.d.). Among other things, the commission aims to implement tools that better allow for cross-country balancing and closer to real-time trade (Nord Pool, n.d.).

2.2.4 Balancing power

An increased share of intermittent renewable energy sources in the power system leads to increasing demand for balancing power; generators that are in stand-by or below maximum power output levels and as such offer a means of regulating the real-time balance between production and consumption (Wangensteen, 2012; Warland, Mo, & Haugstad, 2013, p. 1).

One objective of increased interconnectivity is that a larger system could be less vulnerable to local, regional or national short-term and long-term power imbalance. Short-term power imbalances are related to power system stability; a larger system generally has more "rotating mass", i.e. inertia, and as such offers better stability. Long-term power imbalance is more focused towards security of supply in terms of having sufficient amounts of energy. From a hydropower perspective, a geographically larger system translates into less correlation between inflow of different areas, hence reducing consequences of dry years. For a hydropower system, like Norway's, hydropower-generators offer good short-term control, but yearly inflow variations can have significant seasonal impacts on prices. Thermal power plants have access to "endless" amounts of energy, but often have slower ramping, i.e. their output cannot be regulated as quickly, and so thermal-power dominated systems are more prone to short-term imbalances than energy-shortage. As cross-country interconnectivity increases, it is generally expected that fluctuations in Norway's power prices and production patterns will increase, more in line with continental systems. Statnett comments that the increased integration with the continent has already increased daily fluctuations in Norwegian power production (Statnett, 2015b, p. 7). Increased complexity and dynamic leading to larger price and production fluctuations translates into increased needs for system services such as balancing power.

Intuitively, it is clear that running plants below maximum capacity represents a cost to the producer, so a lot of current research goes into improving the financial tools that compensate for this loss in a way that secures availability of sufficient balancing power. Hydropower with reservoir capacity provide a considerable resource in this respect: Their production levels can be changed rapidly to accommodate variations in load and generation from renewable resources. This ability is enhanced when installed generation capacity is high. Entering 2014, the combined installed power generating capacity in Norway was 32.9 GW, of which 31.0 GW was hydropower (NVE, 2015a, p. 2). Moreover, the balancing capabilities of hydropower plants can be further enhanced by installing pumps, as the next subsection will explore.

2.2.5 Pumped storage

Pumped hydroelectric storage (PHES) involves using pumps to move water from a lower reservoir to a higher one. There are two ways of looking at pumping. One is through an energy perspective. The other is through a price perspective. In terms of energy, circulating water through the same combined pump/power station several times causes about a fifth of the energy to disappear for every loop.[1] This is worthwhile, however, when the water run a significant risk of spillage if the pump is not run. In Norway the goal of pumping has generally been to conserve energy: A specialized pumping station move water from one reservoir to another reservoir, possibly in another river system, which typically has better utilization of the water (Doorman, 2015, p. 66). This use usually involves a one-way flow of water.

The other perspective comes from looking at price differences. The power price is an indicator of the balance of load and generation; lower prices coincide with lower demand for the power produced, and vice versa. Hence the second use of pumps is to increase peak power generating capacity while sacrificing some energy efficiency (Doorman, 2015, p. 66). Here the pumps are installed in combination with a production plant between the same two reservoirs, allowing for a two-way flow of water. “Pumped storage” in this thesis will refer to this type of pumping. The dual ability to produce and pump is often realized through the use

[1] One fifth, or 20%, is roughly the amount of loss assumed in the simulation, see Section 5.5.2.

of reversible pumps – hydropower generators which can also be used as pumps by changing their direction of rotation. The balancing capacity of a power system with such pumps installed is increased in two ways: Firstly, the pumps can be used to assure that the upper reservoir always have sufficient water levels to allow maximum available peak power generating capacity when needed. Secondly, the pumping in itself, through the power the pump consumes when lifting the water up in the river system, can be utilized as a balancing tool: Instead of decreasing generator output when load decreases or intermittent sources increase their production, the pumps can be used to consume the surplus energy. Thus the energy is saved for when it is needed.

This type of pumping has been a hot topic in research and media during the last few years. The flexibility and increased generating capacity it provides have become increasingly relevant due to the aspects discussed in the previous subsections: Norway and other countries are heading for a state of energy surplus (Section 2.1), intermittent power production raises questions about balancing load and generation (Section 2.2.2), and increased interconnection eases pressure on energy conservation while increasing the potential of Norwegian power balancing (2.2.3 and 2.2.4).

So how much pumped storage capacity is realistically available for development in Norway? One estimate based on adding pump storage capabilities between existing Norwegian hydropower reservoirs is 20 GW (Korpås, 2015, p. 6; Vereide, cited in Stone, 2015).

Price variations and pumped storage

Circulating water in a combined pump station means first paying for energy to use for pumping, subsequently selling back only 80 percent of that energy amount. So, in terms of price, pumping is worthwhile only when the power price at the time of production is $\frac{1}{0.8} = 1.25$ times that of the buying price. Hence price fluctuations become an important factor when considering pumped storage.

Now, in systems dominated by large-scale hydropower reservoirs, price fluctuations could theoretically cancel out completely if the reservoir and production capacity is sufficiently large; any increase in power price will cause an increase in production that effectively counteracts the price change and lowers the price back down. In a real system, both reservoir capacity and installed power generating capacity can be subject to constraints in this respect. Limited seasonal energy storage capacity causes seasonal price fluctuations. In a nutshell, limited short term power generating capacity causes short term price fluctuations.

Pumped storage can only to a limited degree help conserve energy by pumping to avoid spillage. On the other hand, there is no limit as to how many times water can be pumped in response to short term price fluctuations. However, similar to how unlimited reservoir capacity cancels out all price variations, unlimited capacity for pumping would limit short-term price fluctuations to what is needed to just cover the losses associated with pumping. This affects the economic foundation for installing pumps: Large amounts of pumped hydro in a power system means that the price is set by the pumps themselves, and so their income is reduced to that of seasonal pumping and production of inflow (Henden, 2014, p. 88).

Intermittent renewable energy production, such as wind power and solar power affects storage needs in two ways. It eases the pressure on long-term energy storage by improving the system energy balance. On the other hand, their intermittent nature can cause problems related to the real-time power balance (Warland et al., 2013, p. 2). This will, in turn, increase short term price fluctuations (Warland et al., 2013, p. 2). Consequently, as we move towards a power system where intermittent generation plays a larger role, we also move into the sphere where large-scale short-term pumping might be viable alternative and an important piece of the puzzle.

To comment on the applicability of this discussion to the simulations run in this thesis, one important note has to be made. What is here referred to as "short term" pumping, can be thought of as anything from monthly and weekly cycles of pumping and production down to intraday-cycles on hourly resolutions or shorter. However, the models used in this thesis only treat the hourly timespan in a simplified manner: They have a main time-resolution of one week, wherein every hour of the week is included in one of 16 price periods.

2.3 Renewable technologies

2.3.1 Wind power

Although the energy of the wind has been harvested for generations, and even electricity production from wind is not amongst the newest of technologies, there is still tremendous unused potential in wind power; especially in Norway. Although hard to quantify, Norway's long coast line represents an almost unfathomable resource in terms of both onshore and offshore wind. Offshore wind induces some additional challenges, but could offer advantages in terms of more stable wind conditions (and generally more wind) and placement. Offshore wind may furthermore be floating or fixed to the bottom. Up until the present stage, floating offshore wind-power has been limited to pilot projects, but in late 2015, Statoil (2015) made the decision to take their "Hywind" project from a small-scale pilot to the world's first floating wind farm. Statoil is also involved in several large shallow-water wind farms in UK waters using traditional fixed fundaments, such as the "Dogger Bank" project (Statoil, 2015). Production series from this project is the basis for the UK offshore wind power studied in this thesis. In Norway, development of wind power has been somewhat limited. The main reason is the low price level seen ever since the development of the now long-since repaid hydropower projects of the post-war area. The previously mentioned El-certificate programme (Section 2.1) was thought to contribute to accelerating wind power construction, but the effects have been limited; although some hydropower-projects are covered, the main bulk of power so far has been built in Sweden. For wind power projects, media speculations have been put forth that investment decisions would have to come not much later than 2016 in order to make the 2021 production start deadline of the El-certificate programme period. Hence there have been, and still are, hopes as to whether additional Norwegian projects would be launched during the course of this year. The "Fosen Vind" project is one such recently presented project: Statkraft's stock exchange announcement of February 2016 presented plans to install a total of 1 TW of wind-power turbine capacity in Trøndelag, Norway, making it Europe's largest land-based wind farm (Statkraft, 2016).

Table 2 - Key figures for Norwegian wind power production in 2015. [2]

Combined installed capacity [MW]	873
Average turbine size [MW]	2.3
Production 2015 [GWh]	2511
Production in normal year [GWh]	2220
Usage time & capacity factor 2015	3045 h or 34.7 %
Usage time & cap. f. in normal year	2692 h or 30.7 %

Some of the main statistics of Norwegian wind power anno 2015 is shown in the table above. The average usage time and capacity factor (the two are closely related) in a normal year gives an approximate relation between installed capacity and average yearly production. A usage time of roughly 2700 hours, as indicated in the table, means that a 1 GW plant will produce roughly $2700[\mathrm{h}] \cdot 1[\mathrm{GW}] = 2700[\mathrm{GWh}] = 2.70[\mathrm{TWh}]$ of energy each year.

[2] The data in Table 2 is taken from NVE's yearly wind power report "Vindkraft - Produksjon i 2015", by David E. Weir (2016, p. 4).

Conversely, 1 TWh of energy supplied indicates roughly $\frac{1000[\mathrm{GWh}]}{2700[\mathrm{h}]} = 0.37[\mathrm{GW}]$ of installed capacity. The capacity factor simply indicates what percentage amount of the year the usage time comprises: $\frac{2692}{8760} \approx 0.307$.

According to data from the annual "Digest of UK Energy Statistics" by the Department of Energy & Climate Change, the 2014 installed offshore wind capacity in the UK constituted a total of 4.5 GW, producing a total of 13.4 TWh of energy (Department of Energy & Climate Change, 2015). This means an average yearly energy production of $\frac{13.4}{4.5} = 3.0$ TWh per GW installed (i.e. a usage time of roughly 3000 hours). We note that this number is somewhat higher than its Norwegian onshore counterpart – as expected due to more favourable wind conditions offshore.

2.3.2 Solar power

Solar power may refer to harvesting two different forms of solar energy: Thermal or electrical. Electricity production from solar rays happen through the use of photo-voltaic (PV) techniques. Large-scale grid-connected power generation from solar power using are relatively new. Its popularity has, however, risen exponentially in recent years; a broad spectre of scientists, governments and the public effectively considers it the most promising technology in the process of reshaping the world into something "greener". It allows for both large centralized generation and distributed generation with without large up-front investment costs. In Norway, grid-connected solar power has mostly been limited to commercial building projects, typically zero- or plus-house projects (essentially houses that produce as much, or more, power as they consume). According to Multiconsult (n.d.), installed capacity in Norway as of 2015 was 3.2 MW_{peak} generating capacity producing roughly 2.5 GWh of energy per year (MW_{peak} is related to DC peak power of each solar panel and is generally somewhat optimistic compared to peak delivered AC power, MW_{AC}). Compared to the (modestly developed) Norwegian wind power boasting a capacity of almost 900 MW, the installed Norwegian solar capacity is negligible. In Germany, however, favourable support schemes using feed-in tariffs have created a sizable market for grid-connected solar power.

The German PV industry constituted 38.2 GW of installed capacity and as much as 33.0 TWh of energy production at the end of 2014 (Bundesnetzagentur, 2015). A quick back-of-the-envelope calculation shows that this means an average yearly energy production of $\frac{33}{38.2} = 0.86$ TWh per GW installed. It can be noted that this is only a fraction of the yearly energy production per GW of that of wind power (which was up to 3.0 TWh, as discussed in the previous subsection). Without going into the physics of efficiency in photovoltaic and wind technologies, one reason why the utilization of solar production capacity is smaller than that of wind, is because the sun simply does not (normally) shine all 24 hours of the day. For example, even with full utilization of installed PV capacity during a twelve-hour day, the capacity factor across a 24-hour period of day and night would only be 50%. So although the wind too, varies, it does so throughout all 24 hours of the day, meaning higher production levels.

Chapter 3 Theory: Hydropower scheduling

Norway's unique power system has induced decades of cutting-edge research on production scheduling methods and decision support tools. From nature's side, Norway's cold winters meant that there was always a need for energy storage capacity: Demand is highest during winter due to widespread electric heating, while precipitation falling as snow means that most of the inflow comes during summer.

This chapter introduces some of the basic concepts and challenges related to a hydropower-dominated power system and the modelling of its dynamics. It forms a basis for the following chapter, where the four SINTEF models EOPS, EMPS, ProdRisk and ProdMarket models will be discussed more specifically. The first subsection holds a brief introduction to optimization of hydro power operation and presents two optimization algorithms used for hydropower scheduling; both of which are used in one or more of the models presented. Then, the common division of planning horizons is briefly introduced.

Doorman (2015), Haugstad, Mo, Johannesen, and Wangensteen (n.d.) were particularly helpful in acquiring an understanding of hydropower scheduling methods. Gjelsvik, Mo, and Haugstad (2010), and especially Pereira, Campodónico, and Kelman (1999), provided good and thorough walkthroughs of the SDP and SDDP algorithms.

3.1 Optimization techniques

Hydropower-dominated power systems offer great flexibility. This flexibility poses the question of how to best operate the system. Some form of optimization algorithm is commonly used. In a traditional, centrally controlled power system, the objective has been to minimize the generation costs for a given demand (Doorman, 2015, p. 2). But following a trend of deregulation in the 1990s, many European power systems were no longer under such central control; Norway was an early adopter with the Energy Act of 1990 (Wangensteen, 2012, p. 11). In a deregulated power system, the objective is to maximise the profits for each power producer (Doorman, 2015, p. 2). Although the two objectives are fundamentally different, the objective functions they produce are very closely related; the only genuine difference is that the curtailment cost that society faces is not included in the profit maximisation formulation (Wangensteen, 2012, p. 150). All of SINTEF's hydropower planning software use a cost minimizing approach (Henden, 2015b, p. 6).

For systems dominated by thermal power plants, the most basic approach to optimising operation is to run the machines with the lowest fuel costs, i.e. the lowest marginal costs. For hydropower systems with significant reservoir capacity, however, the approach is usually somewhat different, due to two factors: The marginal costs are very low, and water is a limited resource. Looking at the marginal cost alone would lead to water depletion before any other power plants were started. This would lead to unnaturally low prices for a limited period of time, and very high prices as the reservoirs were emptied. The nature of water as a limited resource has therefore made it necessary to look at the opportunity cost of producing hydropower instead of the marginal cost. The opportunity cost is the "cost" of reduced future income due to producing water now instead of later. The opportunity cost of producing water implicitly assigns a value to the water. A water value is just this: the value of water in a reservoir. More specifically, we generally think of water values as the *expected marginal value* of water, meaning the additional amount we expect to get paid in the future for the last unit of water added (Doorman, 2015, p. 35). Alternatively, from a cost minimizing perspective, it is the value of replacing "costly" thermal generation at some point in the future. This is where we can see the connection to the opportunity cost: The marginal opportunity cost is the cost of no longer having the opportunity to produce that last unit of water at a later time.

The water value is a function of the reservoir level. When reservoirs are completely full, an additional unit of water only leads to spillage, and so the value of this water is zero (Doorman, 2015, p. 45). Conversely, if there is not enough water to supply all loads, the water value is the cost of curtailment of load (assuming no other options available). The water values are based on expected future cost (or income) through calculations of optimal future system operation. Long-term future system operation are commonly calculated using a variant of "the water value method", based on stochastic dynamic programming (SDP) (Gjelsvik et al., 2010, p. 34). EOPS and EMPS models are based on SDP algorithms (SINTEF, 2014a). A new generation of planning tools have also introduced Stochastic *Dual* Dynamic Programming (SDDP) as an alternative approach (Pereira et al., 1999, p. 15). ProdRisk (and hence ProdMarket) uses an SDDP-based algorithm, with elements borrowed from SDP (SINTEF, 2014c).

"Simulation" and "optimization" are used interchangeably in this thesis when discussing the action of running a model, whether the model in itself uses simulation or optimization methods, or both. When discussing hydropower theory, however, this is slightly inaccurate.

Optimization involves mathematical methods that automatically search for and find the best solution to a given problem formulation (Doorman, 2015, p. 15). In hydropower planning, this means that all decisions to produce or hold water is considered in terms of how they affect not just the present, but the future (Doorman, 2015, p. 18). In contrast, simulation methods do not formally search for a globally optimal solution; future ripple effects from present decisions are not explicitly calculated and taken into account (Doorman, 2015, pp. 17-18). Strictly speaking, both the EMPS model and ProdMarket use combinations of simulation and optimization techniques, as will be discussed in Sections 4.1 and 4.3. In the following we will take a look at two optimization algorithms based on dynamic programming.

3.1.1 SDP

Running a hydropower system at minimum cost is commonly formulated as a recursive problem and solved using dynamic programming. The basic approach of stochastic dynamic programming is to start calculations in the future and work your way back towards the present. The algorithm presented in this subsection provides an extension of basic dynamic programming in that it includes stochasticity in the optimization. In practical use, the algorithm is commonly bolstered with finesses that increase functionality or reduce computational time, but the basic features are the same.

The recursive formulation of hydropower planning states that optimization is a matter of minimizing the sum of *present* and *future* operating costs (Pereira et al., 1999, p. 9). Both costs are represented as functions of how much water is stored at the start of the present period, and how much is produced in the same period. We let $c_t(u_t)$ be the cost of running the system in the present period *t* with a production of u_t, and $\alpha_{t+1}(v_t)$ be the future cost of entering period *t*+1 with a magazine level of v_t. Then the optimal production level u_t in this period can be found by solving the following recursive minimization problem (Pereira et al., 1999, p. 9):

$z_t = \text{Min } c_t(u_t) + \alpha_{t+1}(v_{t+1})$

Subject to

$v_{t+1} = v_t - u_t - s_t + \kappa_t$

within production and reservoir limits

where

s_t is spilled outflow in stage t.

κ_t is inflow in stage t.

The key aspect of solving the above problem is, of course, assessing the value of the future cost function $\alpha(v)$. This is where the SDP algorithm comes in.

The continuous magazine level variable v is made discrete by defining a number of possible system states $m = 1, \ldots$, M, corresponding, for example, to reservoir levels of 100%, 98%, etc. down to 0% (Pereira et al., 1999, p. 10). This particular set of states, where M = 51, is commonly used; all models used in this thesis use it (Henden, personal communication, 24.05.2016). The start point in period $t = 1$ is assumed known; in the case of hydropower models it is normally given as user input. For the very last period, period $t = T$, the future cost function is specified; we will set it to zero (how this is done in our models will be discussed later on). Operational costs for each reservoir level □T for period T can then be calculated. Standing in period T-1, the future cost function $\alpha_T(v_T)$ is then known - it is the operational cost of period T. Since inflow is stochastic, however, N different inflow scenarios are calculated, bringing the system to different states in period T. Each inflow scenario $k = 1, \ldots$, K has a probability p_k. This is illustrated by Figure 1 below.

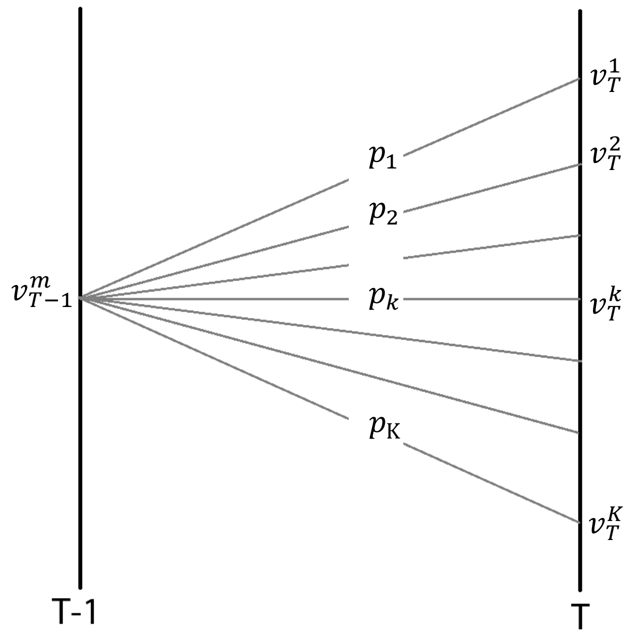

Figure 1 – Magazine levels in period T based on probability of inflow scenarios p_k.[3]

The expected future cost for a given reservoir level in period T-1 is then the probability-weighed mean of all the scenario costs in period T: $\alpha_T(v_T) = \sum_{k=1}^{K} z_T(v_T^k)$ (Pereira et al., 1999, p. 11). After performing this calculation for all M reservoir levels $v_{T-1}^m, m \in \{1, \ldots, M\}$ in period T-1, all future costs α_T are known. Moreover, the future cost function $\alpha_T(v)$ is made continuous by interpolating between each of the discrete reservoir levels. This means that the T-1 optimization problem $z_{T-1} = \text{Min } c_{T-1}(u_{T-1}) + \alpha_T(v_T)$ can now be calculated.

[3] Inspired by a figure in "Course ELK15 - Hydro Power Scheduling" by G. L. Doorman (2015, p. 47).

Those results, from T-1, are then used as the future costs in period T-2, and so on (Pereira et al., 1999, p. 11).

The discussed SDP approach can be summarized in the below algorithm, as suggested by Pereira et al. (1999, p. 12):

```
initialize the end-of-horizon future cost function α_{T+1}(v_T) ← 0
for t = T, T − 1, …, 1
    for each storage value v_t^m, m ∈ {1, …, M}
        for each inflow scenario κ_t^k, k ∈ {1, …, K}
            solve the minimizing problem for initial storage v_t^m
            and inflow κ_t^k
                α_t^n = Min c_t(u_t) + α_{t+1}(v_{t+1})
                    Subject to
                    v_{t+1} = v_t^m − u_t − s_t + κ_t^k
                    within production and reservoir limits
        next
        calculate the expected operation cost over all inflow
        scenarios:
            α_t(v_t^m) = Σ_{k=1}^{K} p_k · α_t^k(v_t^m)
    next
    make the future cost function continuous by interpolating
    between the discrete  reservoir levels {α_t(v_t^m), m = 1, …, M}
next
```

SDP methods similar to the above has been widely used in hydropower-dominated countries (Pereira et al., 1999, p. 15). Its main drawback is that it "Requires enumeration of all combinations of initial storage values and previous inflows. As a consequence, computational effort increases exponentially with the number of reservoirs, the well-known 'curse of dimensionality' of dynamic programming" (Pereira et al., 1999, p. 15). For M reservoir levels and X reservoirs, the recursive problem is solved M^{X} times for each period; only two reservoir states for as little as ten reservoirs require $2^{10} = 1024$ calculations, whereas $\mathrm{M} = 51$ yields a staggering $51^{10} \approx 10^{18}$ calculations. The common solution to this "curse of dimensionality" has been to greatly reduce the number of reservoirs by aggregation (Pereira et al., 1999, p. 15). EOPS and EMPS uses such an approach; all reservoirs in each simulated area are aggregated to a single reservoir (Haugstad et al., n.d., p. 6; SINTEF, 2014b; n.d.-b, p. 12). In recent years, Stochastic *Dual* Dynamic Programming (SDDP) has been developed as an alternative approach.

3.1.2 SDDP

SDDP reduces computational stress compared to the SDP formulation, as it *does not* require complete discretization of all states in order to build the future cost function (Pereira et al., 1999, p. 12). Instead, it uses a piecewise linear approximation of the future cost function (Pereira et al., 1999, p. 16). The linear approximation is made up of line segments, called cuts, as illustrated by Figure 2 below. Each part describes the relation between future costs, commonly represented by water values, and magazine level. The lines are drawn from a single reservoir level and extended to cover all reservoir levels, the slopes given by the derivative of the cost function at each point (Pereira et al., 1999, p. 16). The future cost function is not explicitly calculated, but its value is bound by all the cuts as lower estimates, as described by the following equation:

$$\alpha_{t+1} \geq \varphi_{t+1}^{n} v_{t+1} + \delta_{t+1}^{n} \qquad \text{for } n = 1, \dots, \mathrm{N}$$

The dotted line in Figure 2 represents the estimate of α_{t+1} as set by the above equation. Here, the φ is the slope of each line, and δ the constant term. N is the total number of cuts, or line segments. The t+1's in the formula indicate that, as for the SDP approach, the future cost function in period t is given by cuts from the next period, period t+1.

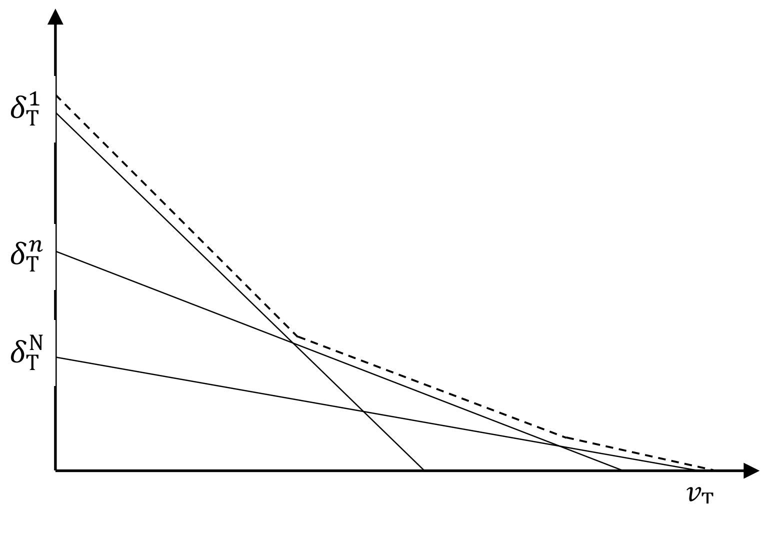

Figure 2 - Piecewise linear future cost function made up of line segments, "cuts".[4]

In the multidimensional case, where several magazines are calculated, the cuts form a linearized multidimensional surface describing the future costs or water value functions for all magazines in the hydropower system (Doorman, 2015, pp. 141-152). And where in the single-magazine case SDDP had the benefit of using a given cut for all magazine levels of that

[4] Inspired by a figure in "Application of Stochastic Dual DP and extensions to hydrothermal scheduling" by Pereira et al. (1999, p. 17).

reservoir, the multi-magazine case is where the beauty of the SDDP algorithm really shows: Each cut can be used to approximate the cost function in totally different system states where *all* magazine's levels are changed. In essence, this allows the SDDP algorithm to escape much of the "curse of dimensionality". By choosing the cuts wisely, one can build relatively accurate future cost function using significantly fewer calculations than for SDP, potentially greatly reducing the calculation time.

The SDDP algorithm involves two main steps. The first is the backward recursion step, which is closely related to the SDP recursion scheme (Pereira et al., 1999, p. 18):

```
set number of cuts N = number of initial storage values M
initialize future cost function for the last stage as zero:
{φ^n_{T+1}, δ^n_{T+1}} = 0 for n = 1, …, N
for t = T, T − 1, …, 1
      for each storage value v^m_t, m ∈ {1, …, M}
            for each inflow scenario κ^k_t, k ∈ {1, …, K}
                  solve the minimizing problem for initial storage v^m_t
                  and inflow κ^k_t:
                        α^n_t(v^m_t) = Min c_t(u_t) + α_{t+1}
                              Subject to            (simplex multiplier:)
                              v_{t+1} = v^m_t − u_t − s_t + κ^k_t          π^k_t
                              α_{t+1} ≥ φ^n_{t+1} v_{t+1} + δ^n_{t+1}      n = 1, …, N
                              within production and reservoir limits
            next
            calculate the m^th linear segment of the future cost
            function in the previous stage:
                  φ^m_t = Σ_{n=1}^N p_k · π^k_t   and   δ^m_t = Σ_{n=1}^N p_k · α^k_t(v^m_t) − φ^m_t · v^m_t
      next
next
```

The simplex multiplier π, associated with the first constraint in the algorithm, represents the rate of change in the objective function with regards to variations in initial storage level v_t, i.e. the slope of a given cut (Pereira et al., 1999, pp. 16-17). The most notable difference between this first step of the SDDP approach and the SDP algorithm discussed previously lies in the outer "for"-loop. In the SDP algorithm, this included a step that completely recalculated the future cost functions based on interpolation of all the updated values $\alpha_t(v_t^m)$ (Pereira et al., 1999, p. 18).

Because the cuts only form an approximate of the future cost function, the objective function, i.e. the total cost function z, is only *approximated* by the results of the backward recursion calculations. Since the true cost function is at least as high as its linearized approximation, the final result for t =1 is a lower bound for z: $\underline{z} = z_1 = \alpha_1(v_1)$, where $z \in [\,\underline{z}\,, \overline{z}\,]$. The second step of the SDDP algorithm deals with finding an upper bound, $\overline{z}$, that can be used to tell us how far from the true z we currently are. Finding the upper bound involves leaving the realm of *optimization* and entering the area of *simulation*. Using a Monte-Carlo simulation, system operation can be simulated, this time starting at the beginning and stopping at the end period (Pereira et al., 1999, p. 19). Decisions along the way are made using the previously calculated cuts. Since the cuts only approximate the true cost function, the resulting system operation will be somewhat suboptimal, and so the simulation provides an upper bound for the cost of running the system optimally (Pereira et al., 1999, p. 19).

An implementation of the simulation step of the SDDP algorithm based on Pereira et al. (1999, p. 19) is shown below.

```
for each inflow scenario κ_t^k, k ∈ {1, …, K}
      initialize storage value for stage 1 as v_t^k = v_1
            for t = 1, …, T
                  solve the minimizing problem for initial storage v_t^k
                  and inflow κ_t^k:
                        Min c_t(u_t^k) + α_{t+1}
                              Subject to
                              v_{t+1}^m = v_t^m − u_t^m − s_t + κ_t^k
                              α_{t+1} ≥ φ_{t+1}^n v_{t+1}^m + δ_{t+1}^n        n = 1, …, N
                              within production and reservoir limits
            next
            calculate total operation cost z^k for scenario k as the
            sum of operational costs for all periods:
                  z^k = Σ_{t=1}^T c_t(u_t^k)
      next
next
```

From the above pseudo-code, it is evident that the inflow scenarios are calculated separately; each represents system operating costs in a given simulated future. Assuming the inflow scenarios are chosen as representative possible future outcomes, the mean of the scenario results estimates the upper bound of the true expected future cost (Pereira et al., 1999, p. 20). By comparing the upper bound estimate to the previously calculated lower bound, we can decide whether the two are within tolerable limits of one another. If we are not sufficiently close, a new iteration can be run with more cuts, or better cuts, to improve the solution. Hence it is “possible to gradually improve the future cost function representation” (Pereira et al., 1999, p. 20).

3.2 Scheduling horizons

The task of minimizing costs or maximising profits in a hydropower system quickly becomes very complex due to factors such as system size, shared ownership, hydrological relations, non-mathematical and average-value-base operational constraints, long time horizons, short time steps and uncertainty (Doorman, 2015, pp. 6, 7). In practice this means that decision support software is needed to plan and operate power systems (Doorman, 2015, p. 6). Ideally, we would want a software that optimized operation of the entire power system on all time-scales and in full detail in one go (Doorman, 2015, p. 23; SINTEF, n.d.-b, p. 12). This has, however, proven hard to implement in practice (Doorman, 2015, pp. 6, 9). Hence, different aspects of the problem are solved separately according to their time horizon, geographical scope and degree of detail (Doorman, 2015, p. 23).

The scheduling process is commonly divided into the phases shown in Figure 3 below (Doorman, 2015, p. 28). It shows what variables are commonly used to couple the phases together, and what solution methods are typically used in each phase. The information flow between the phases and the indicated planning horizon of each phase varies with the task at hand and the characteristics of the system (Doorman, 2015, p. 28).

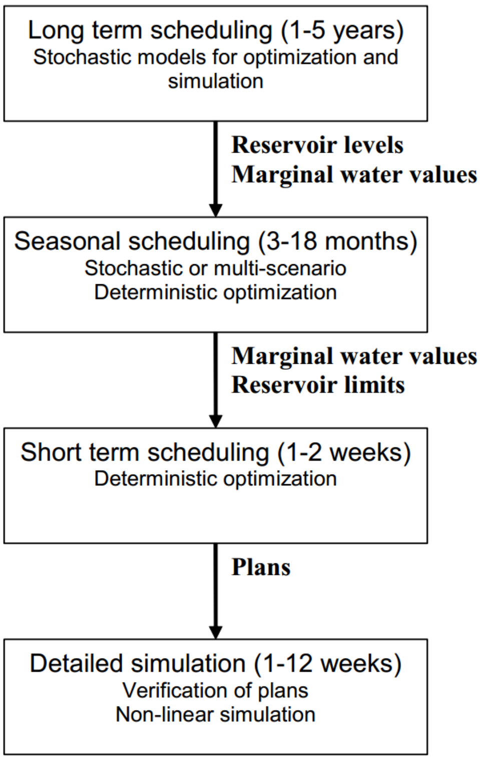

Figure 3 - Scheduling hierarchy.[5]

[5] Reprinted from course compendium “Course ELK15 - Hydropower Scheduling”, by G. L. Doorman, 2015, p.28.

Each of the scheduling phases of Figure 3 are now briefly introduced.

3.2.1 Long term planning

Long term scheduling models are used to analyse long timespans where many input parameters are subject to considerable uncertainty. Stochastic methods are commonly used to deal with the uncertainties (Haugstad et al., n.d., p. 1). Models typically use a time-step of 1 week to 1 month, and a planning period of one to five years or more (Doorman, 2015, p. 28; Haugstad et al., n.d., p. 1). Due to the large systems and long time horizons modelled in the long-term planning phase, some form of system aggregation is normally used (Doorman, 2015, p. 29).

This thesis studies a planning period of 3 years, so our problem can be considered a long term scheduling problem. We also use a main time-step of one week, although price periods are used to include some inter-weekly dynamic (more in Section 4.3.2). The models used also fit the indicated calculation method: "Stochastic models for optimization and simulation". As we have mentioned already (and as we will study in more detail in Chapter 4), EMPS and ProdMarket both use a combination of optimization and simulation methods. And the "stochastic" part is already covered by the "S" for stochastic in the SDP and SDDP algorithms. The only deviation from the "norm" of long-term planning is that ProdMarket, unlike EMPS, does not use aggregation to reduce problem size.

3.2.2 Medium-term/seasonal planning

Put very simply, the seasonal scheduling phase is an intermediate step designed to connect the long and short term scheduling phases. The long term scheduling typically simplifies and aggregates, and thereby disregards some characteristics of the physical system (Doorman, 2015, p. 29). The short term optimization, however, requires detailed information of every reservoir to create robust operational strategies.

Seasonal scheduling tools often rely on the same system description as the long-term scheduling tools, but the mathematical methods used rely less on aggregation and allow for more detailed descriptions of individual hydro reservoirs (Doorman, 2015, p. 29). With the introduction of long term models with more detailed system descriptions and seasonal models that handle stochasticity better, the distinction between the long and medium term scheduling models is becoming "a bit fuzzy" (Haugstad et al., n.d., p. 2). ProdMarket and ProdRisk could fall in this category; their level of detail during optimization has previously been reserved for medium-term planning. We shall also see that EOPS and EMPS models support aspects of seasonal planning.

3.2.3 Short term planning and detailed simulation

The short term planning phases involve finding operational plans that can be directly put into action. This means that as much as possible of the physical characteristics of the system has to be taken into account. Deterministic models are used, meaning that short term prices and inflow are considered known. To cope with uncertainty, several price/inflow scenarios can be run to assess solution robustness (Doorman, 2015, p. 30).

An even more detailed simulator may provide further verification of the feasibility of the solution from the short term model (Haugstad et al., n.d., p. 2).

Chapter 4 Programs used

Two main software tools have been used in working on this thesis: EMPS and ProdMarket. Two more programs of interest are EOPS and ProdRisk, each of which is used by EMPS and ProdMarket, respectively, in their calculations. These four programs will be presented in the following chapter. Some aspects of interest when setting up the models are also discussed; Calibration in the case of EMPS, important run settings for ProdMarket. Finally, a separate section tackles the subject of end valuation of water at the end of the simulation period.

4.1 EMPS and EOPS

Two of the dominating program packages in the hydro-dominated power system in the Nordic countries is “EOPS” and “EMPS” (Wangensteen, 2012, p. 142). Both SINTEF-developed models have been used in the Norwegian and Nordic power market for over 20 years (Doorman, 2015, p. 58). The two models are closely related in that EMPS uses EOPS as a module to calculate the hydropower production in each of its areas; it then uses heuristics to treat interaction between the areas (SINTEF, 2014a). EOPS is a software tool for long term and seasonal hydropower scheduling and expansion planning (SINTEF, 2014b). It provides input to short term models, and is also used to format system input data that are then used in other models such as EMPS, ProdRisk and ProdMarket (Henden, 2015b, p. 10; SINTEF, 2014b).

EOPS calculations, whether performed independently or internally in the EMPS, has two main parts. The first involves using formal optimisation methods and is called the strategy part (Wangensteen, 2012, p. 142). The second part, the simulation part, applies rule-based heuristic methods (SINTEF, n.d.-b, p. 23). In the strategy part, EOPS and EMPS calculates optimal water values using SDP algorithms on an *aggregate* reservoir model of the system (SINTEF, 2014b; n.d.-b, p. 12). The simulation part then performs two steps. It first calculates sum production levels based on the water values from the strategy part (SINTEF, n.d.-b, pp. 20-22). Second, it uses the rule-based “reservoir drawdown model” to allocate the sum production between *individual* reservoirs (SINTEF, n.d.-b, p. 23).

The reservoir drawdown model applies different drawdown strategies during the “filling season” and the “discharge season”. In the Nordic countries, where exceptionally strong seasonal inflow variations are seen due to precipitation coming as snow during winter months, the hydrologic year is commonly divided into a filling season and a discharge season. The filling season starts early summer when the snow starts melting, marking the starting point of a period of massive inflow to reservoirs. For the EOPS and EMPS models, the main objective in this period is to avoid loss of water through spillage (SINTEF, n.d.-b, p. 23). The discharge season is the period that normally has larger discharge than inflow; its objective is to avoid running reservoirs dry while at the same time minimizing the risk of spillage when the spring comes (SINTEF, n.d.-b, pp. 23, 92). As the models use different strategic heuristics for each season, the start point of each season is taken as an input. For the modelled system, the filling season starts around week 18 and ends around week 40, as is also implemented in the run settings of EMPS.

EOPS solves power systems where there are no significant transmission constraints and where the simulated area has relatively homogenous hydrological characteristics (SINTEF, 2014b). EMPS, however, has the capability to simulate multiple areas with transmission constraints between them (SINTEF, 2014a). This is also why the names differ: EOPS is an abbreviation of "EFI's *One-area* Power Scheduling model", whereas EMPS can be written out as "EFI's *Multi-area* Power Scheduling model" (EFI is a former name of SINTEF Energi). EOPS and EMPS also have Norwegian names: "Vansimtap" and "Samkjøringsmodellen", respectively.

A set of rules are used to handle pumps in EMPS/EOPS (SINTEF, n.d.-b, p. 425). The program separates between two types of pumps. *Designated pump stations* are set to pump all available water, subject to magazine restrictions (SINTEF, n.d.-b, p. 425). *Reversible pumps* are also subject to magazine restrictions, but additionally follow a general rule of pumping whenever the relative water value is higher in the magazine where the water is pumped to; the relative water value is calculated based on current magazine levels compared to a target level (SINTEF, n.d.-b, p. 425). This target level is in turn connected to the seasonal objective as set in the reservoir drawdown strategy (SINTEF, n.d.-b, p. 413).

In this thesis EMPS and EOPS have been used in several ways. Firstly, EMPS is run independently and its results are used as a tool for comparison. Secondly, the EOPS user interface is used to set up the data set for ProdMarket. Lastly, ProdMarket also runs EOPS internally, using its results as a starting point and end point (Henden, 2015b, p. 8).

The most important settings used when running EMPS are included in Appendix A.

4.1.1 Calibration of EMPS

In order to secure a reasonable interaction between interconnected areas, which are calculated as separate sub-problems using the EOPS model, EMPS uses a set of calibration factors to adjust “the outside world” as seen from each sub-problem. A good calibration is one that allows the built-in rule-based simulated decisions to lead to near-optimal handling of stored water. We search for a calibration that shows “realistic” reservoir handling (Doorman, 2015, p. 80). Generally this is characterized by good utilization of the available reservoir capacity – wet years should fill up the reservoirs, and dry years should empty them (Doorman, 2015, p. 80). Sound handling of the reservoirs will, in turn, normally give good economic results (Doorman, 2015, p. 80).

Calibration of the EMPS model is done through setting three different calibration factors for each area: The feedback factor, the form factor, and the elasticity factor. The feedback factor is the most important, followed by the form factor (Doorman, 2015, p. 85). In brief, the feedback factor affects the amount of demand considered during water value calculation (Doorman, 2015, p. 86). It is related to how much of the demand in other areas will be covered by the presently calculated area (Doorman, 2015, p. 86). A higher feedback factor generally means that more water is stored in magazines. The form factor relates to how demand is distributed over the year, thereby affecting the slope and shape of magazine and price curves (Doorman, 2015, p. 86). A higher value means larger seasonal load variations, hence normally increasing magazine level gradients between the seasons(Doorman, 2015, p. 86). Lastly, the elasticity factor is related to price elasticity of demand as seen by the model during calculations (Doorman, 2015, p. 86). A higher elasticity factor increases the spread between magazine levels for different inflow scenarios (Doorman, 2015, p. 86).

Calibration in EMPS has traditionally been done manually by assessing the shape of the reservoir level graphs and comparing economic results (Doorman, 2015, p. 75). But in recent years, functionality that allows automatic calibration has been implemented (Doorman, 2015, p. 75). In a relatively rudimental way it logs the changes in economic results as it varies the three calibration factors, one by one, for each of the simulated areas. Although the algorithm is simple, and computation times considerable, the approach provides relatively good results (Doorman, 2015, p. 75). The automatic calibration is controlled by an input file “AUTKAL_INN.CSV”; if the file is not provided, it is automatically generated with recommended settings (SINTEF, n.d.-a, p. 206). The automatically generated settings for our data set is shown in Appendix I.

In the following we will explore and compare a few possible calibration setups; one of which is done manually, and another based on automatic calibration using the below input-file. First out is the “Default” calibration setup, with calibration factors as shown in Table 3 below.

Table 3 - EMPS "Default" calibration.

Omr}de nummer	Navn p} omr}de	Tilbake-koplings-faktor	Form-faktor	Elasti-sitets-faktor
1	NUMEDAL	0.914	0.749	1.000
2	TEV	1.006	1.040	1.000
3	OTRA	1.006	1.188	1.000
4	TERM	0.000	0.000	1.000

The "Default" calibration was part of the default data set. Whether it was created based on an automatic or manual calibration is unknown. It is, nonetheless, considered a good starting point. The calibration was likely considered reasonably good for the unchanged data set, but it may not be anymore, with the changes introduced in the Base case.

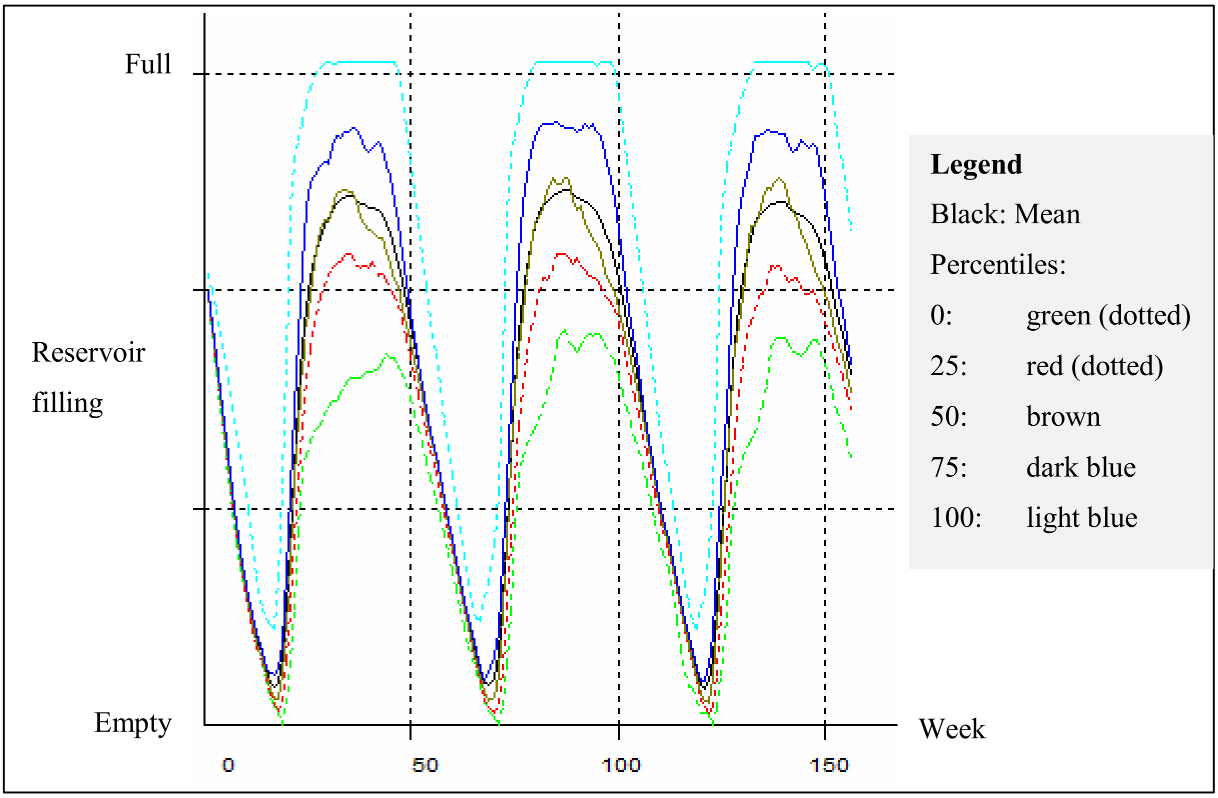

Figure 4 – Numedal area sum reservoir level using EMPS calibration setting "Default" on the Base case data set.

Magazine handling in using the "Default" calibration is good. Magazine capacity in all three areas are utilized well, showing some spillage in the very wettest scenarios and some limited rationing in very dry years. The magazine level graph for Numedal, Figure 4, is shown above as an example. It shows how, during summer weeks, the magazine levels rise towards the full magazine level, which is where the light blue 100-percentile line evens out. We also see that some very limited rationing is needed in extreme cases, represented by the green 0-percentile line. 0-25-50-75-100-percentile graphs for all three waterways are included in – EMPS settings.

The second calibration setting, the “Manual” setting, detailed in Table 4 below, was reached through manual search for realistic looking magazine curves; curves that depicted good utilization of the available reservoir capacity whilst avoiding large amounts of spillage (i.e. full reservoir) or rationing (i.e. empty reservoir). Only the feedback factors and shape factors were changed, not the elasticity factors, in order to limit the amount of variables. This is motivated by Doorman (2015, p. 85), and the fact that the “Default” calibration also has unchanged elasticity factors.

Table 4 - EMPS “Manual” calibration. Based on manual search for realistic magazine handling.

Omr}de nummer	Navn p} omr}de	Tilbake- koplings- faktor	Form- faktor	Elasti- sitets- faktor
1	NUMEDAL	0.940	0.600	1.000
2	TEV	0.940	1.100	1.000
3	OTRA	0.100	1.300	1.000
4	TERM	0.000	0.000	1.000

Although magazine handling using the “Default” calibration was relatively good, the manual calibration introduces some minor changes in magazine handling. In the Numedal waterway, the amount of stored water throughout the year is generally somewhat higher for all scenarios, in an effort to increase robustness in dry years and reduce rationing. This is mainly achieved through raising the feedback-factor from 0.914 to 0.940. The shape-factor is also decreased in an effort to decrease the difference in magazine level between summer and winter slightly, although the results of this is not as apparent in the graphs. In TEV, the mean magazine level has been decreased slightly, this time by lowering the feedback-factor. The form-factor has been increased. Together, the changes form an attempt to utilize even more of the available storage capacity. In Otra, the distance between the 0 and 100 percentile is decreased somewhat while the mean stored water level is decreased, in an effort to lower the amount of spillage while simultaneously decreasing rationing. This has been achieved through significant lowering of the feedback-factor all the way down to 0.1, and increasing the form-factor to 1.3. Again, spotting and predicting the effects of changing the form-factor is not as straight-forward as that of the feedback-factor – contrary to what is generally the case, seasonal changes seem to have decreased as the form-factor increased. Graphs for all three waterways are included in Appendix A.

Table 5, below, shows all nine calibration factors for an automatic calibration run with the automatically recommended calibration parameters.

Table 5 - EMPS “Automatic” calibration. Based on automatic calibration.

Omr}de nummer	Navn p} omr}de	Tilbake- koplings- faktor	Form- faktor	Elasti- sitets- faktor
1	NUMEDAL	1.185	1.129	3.051
2	TEV	2.046	2.083	0.020
3	OTRA	0.057	0.808	2.346
4	TERM	0.000	0.000	1.000

In our case, the automatic calibration was started from the “Default” setting. From this starting point, five main iterations worked its way through 176 calculations of socioeconomic surplus to find a maximum value. The calculated economic surplus is indeed increased by a few percent. But, more importantly, when taking a look at the effects this has on the magazine handling over the simulation period, we see dramatic results.

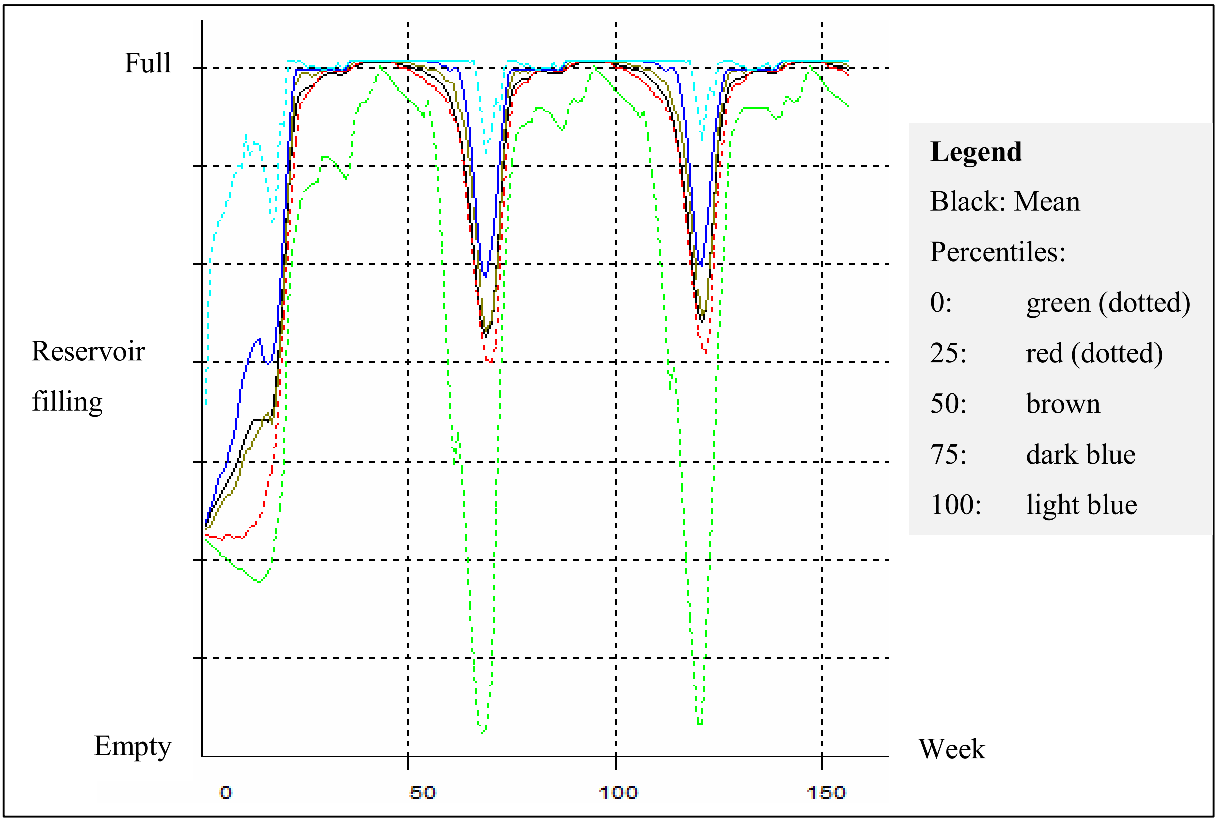

Figure 5 - TEV area sum reservoir level using EMPS calibration setting "Automatic" on Base case data set.

Figure 5 (above) shows how magazine levels in the TEV area flatten out at the top level, indicating full reservoirs, for all but the 0-percentile (the very lowest magazine level recorded across all inflow scenarios). Again, graphs for all three waterways are included in

Appendix A. A full reservoir means that additional inflow is not storable, and would lead to massive spillage of water – water that could have been stored and produced later on to supply more load. This is very clearly not realistic, and not socioeconomically optimal. According to Henden (personal communication, 12.05.2016), such unreasonable results can occur in some cases of inconsistency.

From comparing the magazine handling, we clearly prefer the "Default" and "Manual" settings over the "Automatic" one. Moving on to economic results, we see some interesting results. Table 6 below shows the main economic results of all three different calibration settings. We will now compare the alternatives and decide on which one to use as we proceed.

Table 6 - Economic results, alternative EMPS calibration settings. Best result highlighted. All numbers are totals over 156 weeks.

		Default	Manual	Automatic
Socio-economic surplus [BNOK]		**101.1**	**102.2**	**103.7**
Net income [MNOK]	Numedal	-6.7	13.6	-108.7
	TEV	-54.4	-105.4	470.9
	Otra	158.3	116.2	-1.6
	Term	-268.2	-242.1	-912.7
	Total	**-171.0**	**-217.7**	**-552.1**

The number in the first row is the mean socio-economic surplus as calculated by the "samoverskudd.exe" module of the EMPS model. The following rows contain net income-figures of operating the simulated system, taken from the EOPS module "et.exe". These results are given per area, and are added together manually. First of all, there is a significant mismatch between the two ways of measuring economic results. Interestingly, the setting with the *highest* socioeconomic surplus is also the one with the *lowest* net income (i.e. the highest net cost). As mentioned before, even though the "Automatic" calibration is showing high socioeconomic surplus, its magazine handling is not realistic and clearly not optimal. This is therefore not considered a good candidate. Furthermore, this means that we put more weight on the "Net income"-row than on the socioeconomic surplus. The net income is also what will be used for comparing the EMPS model to ProdMarket later on. Comparing the "Default" and "Manual" calibration, these show relatively similar net income, although "Default" is best. This goes to highlight the difficulty of qualitatively assessing magazine curves and how they indirectly affect economic results. The shape and realism of the magazine curves also matter, however, and which calibration setting is preferable here might be more important than the difference in net income.

All in all, either the “Default” calibration or the “Manual” calibration could have been chosen. As a third option, an effort is made to try and merge the best qualities of the two into a second manual calibration called “Manual 2”. This allows us to create a robust and sober utilization of the system while maintaining good economic results. The rationale behind this is to see whether the calibration setting developed for the Base Case, also gives reasonably good results for the other scenarios later on. As these might introduce a more challenging environment in which to operate a hydropower system, a somewhat careful calibration is more likely to tackle these changes. Table 7 below shows the calibration factors for the “Manual 2” calibration.

Table 7 - EMPS “Manual 2” calibration. Based on "manual 1" and "Default" calibrations.

Omr}de nummer	Navn p} omr}de	Tilbake-koplings-faktor	Form-faktor	Elasti-sitets-faktor
1	NUMEDAL	0.930	0.745	1.000
2	TEV	1.000	1.040	1.000
3	OTRA	1.006	1.188	1.000
4	TERM	0.000	0.000	1.000

Starting with Numedal, the feedback factor, now 0.930 is increased somewhat from the “Default” setting of 0.914 towards the “Manual 1” level of 0.940. This is in order to increase the buffer in stored water during the winter months, in case of dry years. The shape factor is almost identical to that of “Default”. In TEV, the settings are almost identical to that of “Default”. The feedback factor is just barely inched towards the 0.940 in the “Manual 1” calibration, down 0.006 to 1.000. In Otra, the “Default” setting is kept as is. Largely, then, “Manual 2” is similar to “Default”, but stores slightly more water in the Numedal waterway. Running the simulation and studying the magazine graphs for “Manual 2”, shows just this: The TEV and OTRA waterways are seemingly identical to that of “Default”, while the Numedal graph is just a tiny bit higher. Graphs for all three waterways are included in Appendix A.

Table 8, below, shows net income results of “Manual 2”. It, too, shows that the “Manual 2” calibration is very similar to the “Default” calibration – but marginally better, in fact. Moving on, the “Manual 2” calibration will be used.

Table 8 - Economic results, new alternative EMPS calibration settings. Best result highlighted. All numbers are totals over 156 weeks.

		Default	Manual_1	Manual_2
Net income [MNOK]	Numedal	-6.7	13.6	-3.9
	TEV	-54.4	-105.4	-57.3
	Otra	158.3	116.2	156.1
	Term	-268.2	-242.1	-265.0
	Total	**-171.0**	**-217.7**	**-170.1**

4.2 ProdRisk

ProdRisk shares much of its basic principles with EOPS; the run interface is similar, the model's input and output formats are similar, and it solves the same type of problem: a local medium to long term planning problem (SINTEF, 2008, 2014b). The key difference lies in how its results are achieved. Where EOPS uses large-scale aggregation followed by heuristic methods such as the reservoir drawdown method, ProdRisk incorporates all the modelled physical detail into a comprehensive mathematical optimization using a Stochastic Dual Dynamic Programming (SDDP) algorithm (SINTEF, 2008, 2014c; Warland et al., 2013, p. 1). This makes ProdRisk especially powerful in that it solves even complex river-systems with very good results (Henden, 2015b, p. 5). The increased level of detail greatly increases the problem size, hence calculation time effectively limits the problem size ProdRisk can handle (Warland et al., 2013, p. 1).

As described in the basic SDDP-algorithm in section 3.1.2, ProdRisk approximates future costs by calculating cuts for each inflow scenario. Moving on from the discussed algorithm, however, and unlike EOPS and EMPS, ProdRisk is designed to run its optimization on a large number of reservoirs. This means that the cuts are not linear line segments on a two-dimensional cost curve, but surfaces in the multidimensional space spanned by the reservoir levels of all magazines (Henden, personal communication, 23.05.2016). As discussed in 3.1.1, if SDP were used, this would mean that cost calculations would have to be repeated for each possible combination of reservoir levels. Luckily, ProdRisk's backward recursion is able to greatly reduce the number of computations required by taking advantage of the simplifications allowed by the SDDP approach. Instead of changing one reservoir level at a time, as in SDP, ProdRisk changes all reservoirs simultaneously according to results from the inflow scenarios simulated in the forward simulation.

For “iteration zero”, the very first backward optimization, however, no previous forward simulation can be used to specify each reservoir’s current reservoir level. Hence, what is called the “guideline curve” is used as a basis to create five “guessed” magazine levels (Henden, personal communication, 23.05.2016). The guideline curve is the result of the first step of EOPS’s simulation part, where sum production levels are simulated (Henden, personal communication, 24.05.2016). In addition to using the magazine levels in the guideline curve directly, two more magazine levels are calculated by averaging the guideline curve with the full and empty reservoir levels, respectively (Henden, personal communication, 23.05.2016). The last two reservoir levels are the full and empty levels, reaching the total of five “scenarios” for magazine level that are calculated in the initial iteration.

For each subsequent iteration of ProdRisk, the resulting magazine level from the forward simulation is added to the set of reservoir levels calculated in the backward recursion. And for each iteration, all inflow scenarios have separate magazine levels. In the backward recursion, a new cut is calculated for each new set of magazine levels (Henden, personal communication, 23.05.2016). Hence, for N = 50 inflow scenarios, as used in this thesis, every iteration introduces 50 new cuts for each simulated week. After 50 iterations, this would mean 2505 cuts, counting the first five guessed magazine levels. Now, in order to reduce computer memory usage, the number of cuts carried forward from one iteration to the next is limited by removing cuts that are seldom or never binding for the future cost function (Henden, personal communication, 23.05.2016). In this thesis, the limit used is 500. Even with this limit, the number of cuts is considerable; over a three year, or 156 week, simulation, the total number of cuts is $500 \cdot 156 = 78\ 000$. And that number multiplies as price points are considered.

ProdRisk is normally run with an exogenous price series as input (Henden, personal communication, 23.05.2016). This means that the input price is handled as a stochastic market price, unaffected by local decisions. The stochasticity of the price is handled through the use of *price points* and a *price model*. The price model is a discrete Markov chain which defines the probabilities of moving from each price point in one period to each new price point in the next period (Mo, Gjelsvik, Grundt, & Karesen, 2001, p. 2). Together, the price points and transition probabilities model the sequential correlation of prices from one week to another (Gjelsvik et al., 2010, pp. 39-40). ProdRisk (and ProdMarket) uses the same price modelling module as EOPS and EMPS, called “Genpris”, which follows the approach described by Mo et al. in 2001 (Henden, personal communication, 23.05.2016). For each period of the simulation, calculations are performed for several different prices; these are the price points.

Each price point is calculated as a discrete state, they cannot be approximated by cuts as is required in the SDDP algorithm, so in this regard elements of the standard SDP approach is used (Gjelsvik et al., 2010, pp. 39-40). In ProdMarket, seven price points are used when ProdRisk is run; two "extremes values" and five intermediate ones (Henden, personal communication, 20.05.2016). As a SDP-approach of complete enumeration of states is used, the number of cuts increases proportionally with the number of price points. In our case, with a cut limit of 500 over a 156 weeks simulation period and 7 price points, the total number of cuts *used* is $500 \cdot 156 \cdot 7 = 546$ thousand. The total number of cuts *calculated* is much higher: 50 inflow scenarios $\cdot$ 7 price points $\cdot$ 156 weeks $\cdot$ 50 iterations ≈ 20 million. No wonder computation time is a challenge.

4.3 ProdMarket

In many ways, ProdMarket is to ProdRisk as EMPS is to EOPS. The same way EMPS utilizes EOPS-modules to solve local sub-problems, ProdMarket too is built upon splitting up its problems, feeding them to ProdRisk and then combining the local solutions into a "global" solution. Hence ProdMarket is aimed at solving larger problems, similar to EMPS.[6] Figure 6 below shows one way of visualizing ProdMarket's inner wiring.

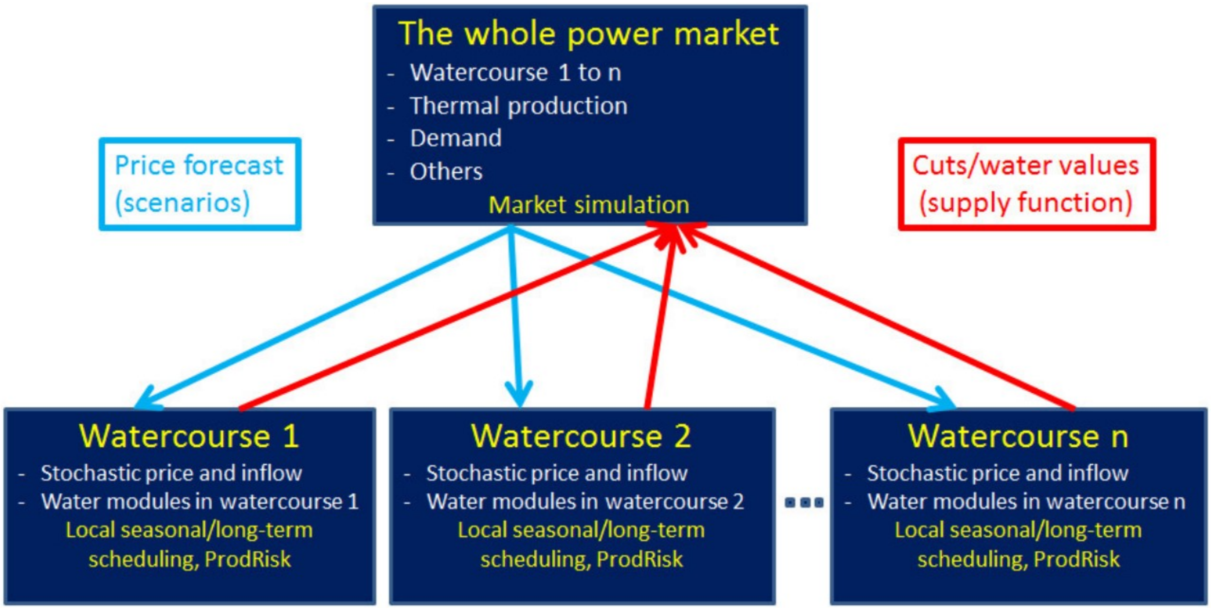

Figure 6 - ProdMarket: Basic principle, decoupling, relation to ProdRisk.[7]

[6] The current version of ProdMarket does not support restrictions on transmission capacity, which can be a drawback in terms of usability for geographically widespread systems (Henden, 2015b, p. 23).
[7] Reprinted from "ProdRisk som fundamental markedsmodell, ProdMarket - Markedsmodell basert på SDDP", by A. L. Henden (2015b, p. 7). Reprinted with permission.

The main idea behind ProdMarket is to mimic the dynamics of the power market (Henden, 2015b, p. 6). Each local problem consists of one river system and can be seen as a local production entity. Each "producer" then minimizes his costs (using ProdRisk) for a given market price; all producers are viewed as price takers (Henden, 2015a, p. 4). A set of cuts work as supply curves and are returned from each sub-problem, and a market clearing is run on the overall system (Henden, 2015a, p. 4; 2015b, p. 6). The resulting market power price is then returned to the sub-problems to solve these again – this loop iterates until the power price stabilizes (Henden, 2015b, p. 6).

When ProdRisk completes a local simulation, the sub-problems each return a number of cuts that describe their future cost function. Together, they define water values for all magazines in the data set, for all magazine levels and price levels. All of which is used in the overall market simulation. In essence, the market simulation module in ProdMarket is identical to ProdRisk's forward simulation (Henden, 2015b, p. 9). The main difference is that ProdMarket incorporates all waterways, so it has all the information it needs to calculate the power price as an internal market value based on supply and demand (although ProdMarket can be run with an exogenous price as well). Since the forward part of the SDDP algorithm is much faster than the backwards recursion step, the ProdMarket market simulator requires little computation time compared to the ProdRisk problems.

As each outer loop iteration completes a forward simulation in the market simulator, the global power price is stored in a spreadsheet file "X1.csv". It holds power prices for all price periods in all weeks, so $16 \cdot 156 = 2496$ price points in our case. It also has separate prices for each inflow scenario – 50 in this case, so $50 \cdot 2496 = 124800$ separate price levels in total. Before being sent to each separate waterway sub-problem, these 50 discrete scenarios are reduced to a Markov chain of seven price points with transition probabilities between them (as discussed in the previous subsection). The price record "X1.csv" is read into the "Genpris" module to create the price model, which is then stored in a separate "X1.PRISMOD" file. Considering all waterways as "price takers" means that the input price is handled as a stochastic market price, unaffected by local decisions. In effect, ProdRisk is run with the calculated market price as an exogenous price record.

For the first ProdMarket iteration, there are no cuts from which to base the forward market simulation. ProdMarket then runs the EOPS model internally to set the initial power price for all weeks (Henden, 2015b, p. 8). Water values from EOPS's strategy part are stored in the file

“VVERD_000.EOPS”. At the end of each simulation period, the same water value matrix is also used to value the water left in the hydro reservoirs as the simulation ends (Henden, personal communication, 20.05.2016). This will be a topic for further discussion in subsections 4.3.3 and 6.5.5 and throughout the result chapter.

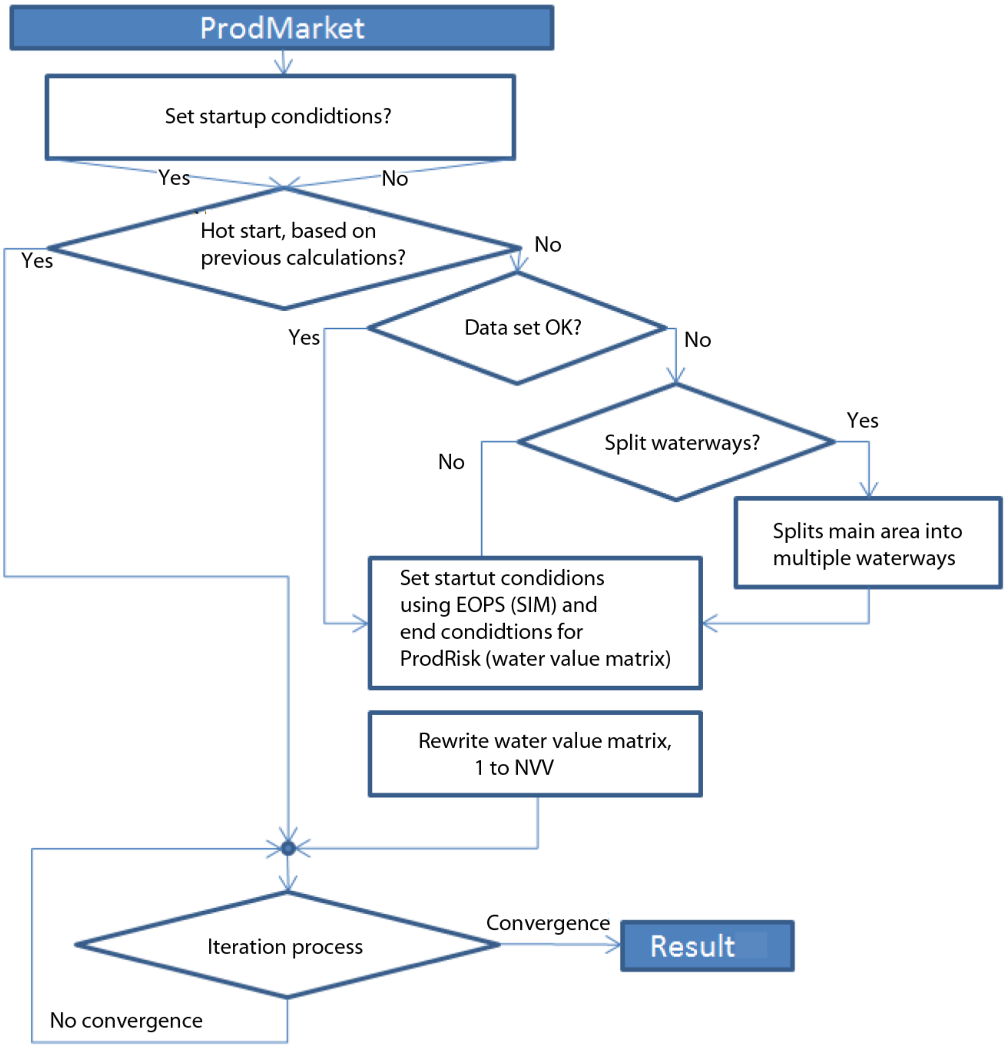

Figure 7 - Flow chart, ProdMarket, with user input.[8]

Running the ProdMarket-script, a series of choices are presented to the user. Above, Figure 7 shows the options and underlying mechanisms as a flow-chart. For this thesis, the sequence of answers has been “No”, then “Yes”. As is evident from the chart, this immediately starts the iteration process; no more user input is required. Answering “Yes” to the second question initializes what is called a “hot start”, which surpasses a couple of initial setup steps. The hot start essentially bypasses the initial step of running EOPS to set the end-of-period water

[8] Translated to English and reprinted from “ProdRisk som fundamental markedsmodell, ProdMarket - Markedsmodell basert på SDDP”, by A. L. Henden (2015b, p. 10). Reprinted with permission.

values in “VVERD_000.EOPS”. Instead, the existing matrix is use. The reason for this is linked to problems with the 1toNVV-module which changes the dimensions of the EOPS water value file to make it suitable for use in ProdMarket. For the very first run of ProdMarket then, a manual workaround was used to take care of the “missing” steps detailed in Figure 7. This software bug is discussed in a following paragraph in Section 4.3.2.

The following subsections look into different aspects of ProdMarket. First off, some important run settings are discussed.

4.3.1 Run settings

The settings used when running ProdMarket are set by editing the initialising file “INITIALISERING.PDMARKED”; the full list is included in Appendix B. The file specifies a number of the parameters discussed in the previous and following subsections. Amongst one, it sets the simulation period, three years or 156 weeks in this thesis. Start magazine level for all magazines in week 1 is set to 70%. This is, of course, unlikely in a real scenario, but having a realistic start point is not crucial when comparing models. It is also assumed that minor inaccuracies in the start condition can be accepted: It will affect the first few weeks of simulation, but further out in the simulation period, it is assumed not to affect magazine levels notably, as the seasonal fluctuations overshadows everything else. The validity of this assumption will be commented in the results. The input settings also set the previously discussed limit to the number of cuts used in each ProdRisk sub-problem to 500. Its value has limited effects on computational times as it only limits the amount of cuts *stored*, not *calculated* - it mainly affects memory usage (Henden, personal communication, 23.05.2016).

Several of the parameters set in the initializing file affect result convergence. The two convergence criteria for ProdMarket govern the allowable absolute value change and standard deviation change in power prices between iterations. The setup file also sets the maximum number of iterations to run in case the convergence criteria could not be met. Both maximum number of inner loop iterations in ProdRisk and outer loop iterations of ProdMarket’s market simulation is set. ProdRisk is limited to 50 iterations; ProdMarket to ten. Both programs normally reach these limits before their convergence checks stop the iteration. Experience has shown that ProdRisk nonetheless provides good and stable results. As for ProdMarket, the maximum number of outer loop iterations is set to 10 as this empirically gives a reasonable trade-off between calculation time and accuracy on this particular data set (Henden, personal communication, 24.11.2015). Nonetheless, performing only 10 iterations could provide sub-optimal results; convergence status will be commented in the results section (section 6.1).

Depending on what is chosen in the initialising file, a number of features can be chosen: Parallel mode or serial mode, CPLEX or COIN, with or without MPI. We are running parallel mode meaning that all inflow year scenarios are simulated separately in parallel, as opposed to serial mode where the inflow years are simulated serially and magazine filling at the end of one inflow year is the start level of the next (Henden, personal communication, 02.03.2016). The other settings will be explained in the following subsections. But first, some software bugs and minor source code changes are presented.

4.3.2 Source code errors, changes

When working with, and evaluating the results from, ProdMarket, it should be noted that at the current stage, ProdMarket is not a finished product (although it could be said that this type of models never is). In essence, ProdMarket remains a "proof-of-concept" model, created and refined just to the level of what is required to run tests and generate results. The scripts and executables used in this thesis is under continuous development to include more functionality, correct software bugs and improve results. Support for wind and solar generation series was added in one such recent update. The update is, however, quite basic in its implementation: None of the user interfaces are updated to accommodate for the change, but the basic underlying mechanisms are present. As such, all wind- and solar-power data presented in the results later on, will be either manually created from the input files, or mirrored from the EMPS model's results. Throughout the study period, several of the modules have been replaced by improved or modified versions, e.g. to accommodate for changes in run settings. Most of the new code written to create ProdMarket was programmed in the "Python" programming language, but ProdMarket uses several existing modules from previous programs built in "Fortran" (Henden, 2015b, p. 6). All changes in the ("Fortran"-based) executable modules have been done by Arild Lote Henden at SINTEF. The new Python-scripts, however, was accessible to manual change. In the following, a few of the errors found are described along with the implemented outline for the solutions to the problems.

Software bug: Prodrisk_cplex.exe

When ProdMarket starts the ProdRisk sub-problems, it does so by calling one out of four executable ProdRisk files. The four files perform the same basic tasks, but cover different options in terms of technologies and parallelisation. As run settings were changed in this thesis as compared to previous work with the model, an error was identified: In enabling the "CPLEX" LP-solver, the executable file "prodrisk_cplex.exe" was called from the "runprogProdRiskDel()"-method in the Python-script "funksjoner2.py". This executable causes ProdMarket to crash. To avoid the problem, the Python-script was edited to force execution of the MPI-enabled version, "prodrisk_cplex_ms_mpi.exe". Since MPI is used to handle communication between multiple processor threads, it was by default turned off for single-thread problems (as was the case for the TEV-waterway in this thesis).

Software bug: Prodrisk_marked.exe –CPLEX

A second problem related to enabling CPLEX was found in the "runprogProdRiskMarked()"-method of the "funksjoner2.py" Python-script. The method starts up the ProdMarket market simulator executable "prodrisk_marked.exe". When enabling CPLEX, however, it attempted to run a file named "prodrisk_marked_cplex.exe", a file that was not present. As the market simulator is considerably faster than the ProdRisk sub-problem instances, it is not crucial to run CPLEX as opposed to COIN here, hence a CPLEX-version of the market simulator has not been implemented.

Result presentation: ET.exe, kurvetegn.exe

Updates to ProdMarket that added support for wind power and discontinued use of a certain file type had unintended consequences in regard to result presentation using the ET.exe and kurvetegn.exe modules. A file name change meant that when extracting a particular type of results, outdated files left over in the data set where used instead of the updated ones. Due to its narrow effect, the problem was not identified until pump data for Scenario A was analysed. A solution was provided by Arild L. Henden by creating and using a separate version of the two modules when extracting ProdMarket results. Furthermore, income from wind power is not included in ProdMarket result calculations using ET. This was also discovered during Scenario A analysis, and is an important consideration when comparing ProdMarket to other wind-enabled models.

Water value matrix for 16 price periods: 1toNVV.exe

The previously discussed Figure 7 illustrated how an executable module named "1toNVV.exe" was used to rewrite the water value matrix used as ProdMarket starts. More specifically, the 1toNVV module rewrites the EOPS water value matrix in "VVERD_000.EOPS" from having only one dimension to seven, i.e. the number of price points (before rewriting the file, however, it saves a backup of the original in

"VVERD_VANSIMTAP.EOPS"). It does so by copying the *single* price of each price period in EOPS to each of the *seven price points* per price period used in ProdMarket. This is illustrated in Figure 8 below.

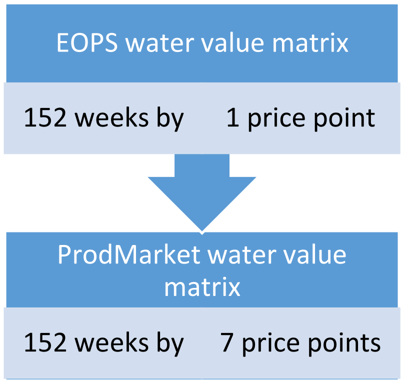

Figure 8 – Outline of 1toNVV module.

The 1toNVV module, it turned out, did not support the move to 16 price periods. The matrix in "VVERD_000.EOPS" was therefore manually expanded before running ProdMarket for the first time. Subsequently, this file remained unchanged, and the 1toNVV-module was bypassed, by starting ProdMarket in "hot start"-mode for each new simulation case. The possible effects of this seemingly small detail will be revisited throughout the thesis: Not updating the end value matrix is means that the changes introduced in each simulation case are not reflected in the internal end magazine valuation in ProdMarket.

4.3.3 End valuation of water

ProdMarket's (and EMPS') results are affected by the start and end boundary conditions of the (in this case) three-year simulation period. As discussed, system state for the start point is given directly in the form of a specified magazine level for all magazines in the system (other methods are available, but that is what is used in this thesis). The end magazine level, however, is calculated by the model model's algorithm, but is inevitably tied to the end valuation of stored water. For both EMPS and ProdMarket, the simulation end values are based on internal water values from each model's calculations (Henden, personal communication, 30.05.2016). A higher end valuation leads to higher end magazine levels, and vice versa.

Ideally, given the right start and end conditions, all three years of the simulation period would be equal (if certain long-term factors such as time valuation of money is not considered). This would indicate that neither start- nor end-point setting influenced decisions in the other periods. This is, however, hard to achieve, and can only to some extent be assumed valid.

Luckily, though, the second year results are, thanks to the violent seasonal variations of the studied hydropower system, relatively robust in terms of simulation period boundary conditions: The actions taken to account for upcoming seasonal fluctuations simply overshadow most aspects regarding other seasons than the very next one. Simulation start and end boundary condition is the reason why some users of the EMPS model, for instance, simulate three years as in this thesis, but consider only the second year results (Henden, personal communication, 27.05.2016).

All in all, end valuation of water is a particularly challenging aspect of designing and comparing hydropower optimization tools. The core challenge is that the value of water in a hydropower system depends on how the system is operated in the future. Since the future is uncertain, there is no certain way of correctly valuing a given unit of water. Valuating reservoir levels at simulation period end is used for two slightly different purposes:

i. Internal use in the model's optimization algorithm. Provides an end boundary condition for the simulation period.

ii. External result analysis. Provides a means of adjusting economic results for changes in magazine levels.

This section discusses the first use. The second is discussed in Section 6.5.6 as the simulation results are analysed.

One way or another, hydropower-models are responsible for creating their own boundary condition and hence controls their own performance and economic result. From the viewpoint of each model, the best known estimate of how to run, and hence valuate water in a system, is the model's own calculations – which, in turn – depend on the end valuation. This two-way dependency means that some form of iterative procedure is commonly used (Henden, personal communication, 31.05.2016).

One approach used to set end value in hydropower planning is to aim for a solution where start and stop states are equal. This is used in both EMPS and ProdMarket (Henden, personal communication, 31.05.2016). More specifically, the models aim to match the water values of the last week of year three to the last week of year two (Henden, personal communication, 31.05.2016). Starting from the last week of the simulation period, period $t = T = 156$, a rough "guesstimate" future value is assigned for the value of water in week T+1 (Henden, personal communication, 31.05.2016). The model then runs its backward optimization algorithm until it reaches period T-52 = 104 (Henden, personal communication, 31.05.2016). The water values in this week is then compared to those of week T and, if there is no match, a new guess is made for week T and a new iteration is run (Henden, personal communication, 31.05.2016). The new guess could be the water values calculated for week T-52 (Henden, personal communication, 31.05.2016).

When enough iterations are performed so that start and end states of the last year are sufficiently close, the model continues to calculate the rest of the simulation period as per usual. In practice, the iteration loop can be viewed as a way of expanding the simulation period: For every re-run of the last simulation year, it is as if the end boundary condition of the simulation period is moved one year into the future. In this respect, it can be said that each model simulates more than three years ahead; it is an intuitive way of understanding how the initial end valuation guess has less and less impact on the actual simulation period. The result of the iteration scheme is important as it directly affects the decisions made in previous time steps. Higher end value increases power prices and magazine levels, particularly in the weeks near the end of the simulation period.

As stated, such an iterative approach is used by the both EMPS and ProdMarket (Henden, personal communication, 31.05.2016). There are some minor differences, however, that turn out especially relevant in our case. Whereas EMPS calculates and uses its own water values for end valuation, we remember (from the start of Section 4.3) that for ProdMarket, both start- and end-point values were set by the water value matrix "VVERD_VANSIMTAP.EOPS" which was calculated by EOPS. This solution has been applied since Henden (2015b) revealed problems with how ProdMarket handled end valuation if the water values were taken directly from ProdMarket's own water value matrix. The problem identified was, in its simplest form, that the iteration scheme had problems converging: Power prices and magazine levels kept increasing for each iteration (Henden, 2015b, pp. 12-14). The solution, then, was to use the EOPS model when running the end value iteration (Henden, 2015b, pp. 12-14). However, having ProdMarket use EOPS to set its water values suffers a flaw for the exact settings of this thesis: EOPS does not support wind power.

Elevated end valuation

This paragraph introduces the idea that the particular settings of this thesis could have ProdMarket set up for flawed internal end valuation of water. It is an idea that will be frequently revisited in Chapter 6. Three possible factors have been identified that could contribute to the same effect: elevated water values in EOPS, which in turn sets the internal end valuation of ProdMarket. The three factors along with the outline of how they could possibly heighten end valuation are listed below:

1. An error in "1toNVV" means EOPS is not re-run to update changes made to data set.
   - The default data set had considerably more demand $\xrightarrow{yields}$ higher prices and end value in EOPS.
   - Changes made to the scenarios introducing new hydro and pumped storage capacity, or additional production, are not considered $\xrightarrow{yields}$ higher prices and end value in EOPS.
2. EOPS does not support wind, so, in effect, runs calculations with more demand $\xrightarrow{yields}$ higher prices and value in EOPS.
3. PM is generally better than EOPS $\xrightarrow{yields}$ lower power prices $\xrightarrow{yields}$ higher relative end value in EOPS.

Here, only a brief introduction is presented as to the line of thought for each one. It should be stressed that these are not facts, but theories.

First, the 1toNVV-software bug described in the previous sub-section is considered plausible to increase ProdMarket's water valuation by not including changes that would have decreased system costs – such as decreased load levels. Second, on data sets with wind power, EOPS will miss out on the extra energy that the wind provides, and as such will have higher system costs. The presumed effect of this is higher water values, hence an unnaturally high internal end water valuation. Third, ProdMarket being a superior modelling tool compared to EOPS could possibly mean that EOPS yields relatively higher end valuation than what is "correct" for ProdMarket: If ProdMarket runs the system cheaper, that could mean water values are also lower.

Section 6.5.5 will revisit this subject, commenting on how these factors affect the results.

4.3.4 Price period (load period)

The EMPS model and ProdMarket are both long-term hydro-planning models in terms of their capability to handle long time-scales. But as the limits of computational power have expanded, the long term models have been able to include more and more short-term detail. Both EMPS and ProdMarket have a main time-step in inflow and price stochasticity of one week. In itself, this would normally indicate that price and production would be calculated as average values per week – disguising the internal fluctuations within each week. But by using *price periods*, intra-week and intra-day variations in price can be exposed. The price periods define load and renewable production levels that each represent a given number of hours spread throughout the week; combined, they represent a rough estimation of daily and weekly price variations (Doorman, 2015, p. 76). The term *load period* has traditionally been used for models without support for non-regulated renewable power, such as the EOPS, but the decision has been made to deviate from this convention as the term would be misleading seeing as both of the main models in this thesis also consider *production levels* from renewable sources in each price period.

EMPS and ProdMarket support up to one price period per hour of the week (SINTEF, 2014a). The resolution is limited to an hourly scale as load and unregulated power production (such as new renewables) are given down to hourly levels. In this thesis, load and renewable generation (wind and solar) are indeed given as hourly inputs – as 168 individual data points per week. The number of price periods used, however, is limited to 16. This number of price periods is chosen at it is at the very edge of what is acceptable in terms of calculation time. The 168 hours of each week is distributed between these 16 price periods as indicated in Table 9 below. Within each price period, the hourly load and production levels are aggregated to average levels, and a common price is calculated. Choosing what hours to group together into price periods is not necessarily straight forward. Some hours may be combined without notable loss in accuracy, whereas some time-periods require as much detail as possible to depict realistic variations. Finding the optimal distribution of hours is a matter of analysing load and production profiles throughout the all the input years. An in-depth analysis has not been attempted here. Instead, a simple division of two different daily profiles, each consisting of eight equally long price periods are used.

Table 9 – Price periods. Hours of the day horizontally, days of week vertically. All hours in same price period shaded.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
M																								
T																								
W		**1**			**2**			**3**			**4**			**5**			**6**			**7**			**8**	
T																								
F																								
S		**9**			**10**			**11**			**12**			**13**			**14**			**15**			**16**	
S																								

Each price period stretches over three consecutive hours. These hours are grouped together as one, implicitly assuming that load and renewable production figures are relatively stable throughout this period. The assumption is not perfect, but finer than a three-hour resolution is not practical due to calculation time. However, even with a three-hour resolution over a week, the number of price periods would be $\frac{168}{3} = 56$. This number is reduced to 16 by also grouping hours together across days. In our case, the same three and three hours across all five workdays are grouped together into bulks of 15, as indicated in Table 9. Similarly, three and three hours from each of the two weekend days are grouped together to bulks of six. Once again, this multi-day collection implicitly states an assumption regarding load and generation. The first assumption is that load is relatively equal at a given time across all weekdays. This is motivated by the simple notion that load levels are similar the days when consumers have similar daily routines, and the largest single impact on this is whether or not most people go to work. In Norway, this assumption in generally quite good. The second implicit assumption, that renewable production is at similar levels across work- and weekend-days, is not without flaws. Wind and solar production is directly affected by weather changes, hence averaging production levels across several days will smooth out daily variation. This is especially true for wind power, which is *only* affected by weather. The hypothesis works slightly better for solar generation, which also follows the daily "routines" of the sun. The loss in accuracy in terms of averaging variable renewable production is an unavoidable consequence of reducing the number of price periods and computation time.

Increasing the time resolution of hydropower planning tools will continue being a subject of improvement. Kyllingstad (2015) had four price periods. The move to 16 price periods is an attempt at studying whether the increased resolution will reveal additional dynamics in the simulated hydropower system. In particular, it is a response to the intuition that pumped storage hydropower sees higher utilization when more short-term price fluctuations are revealed, as suggested in Kyllingstad (2015, p. 38). The sequential distribution of hours into price periods, as was shown in Table 9 above, also means that plotting the price periods in order from one to 16 will show actual daily 24-hour profiles over the two aggregated days, the "Workday" and "Weekend".

See Appendix D for the input file to the model describing the price periods used.

4.3.5 Computation time

Even as Moore's law works its magic in terms of increased processing power in new computers, the need to work on decreasing computation time has not lessened. Along with the increased processing power, more and more calculation-heavy ideas to utilize this power surfaces. ProdRisk was one such power-hungry idea; ProdMarket its follow-up idea to increase ProdRisk's reach by moderating its calculation needs. The main bulk of computation time in optimising hydropower production planning is devoted to solving the large LP-problems that follow this type of SDP and SDDP problems. So when tackling computational times, you try to do two things: Maintain accuracy while minimizing problem size, and solve the resulting problem as fast as possible. What ProdMarket does compared to ProdRisk, is that it maintains the same level of system detail, while decreasing the size of each LP-problem solved. Nonetheless, ProdMarket requires immense amounts of calculation, as large systems are studied at great detail. with the default run settings, the 50-unit hydropower system studied in this thesis would take in excess of two days of simulation per ProdMarket iteration (of which 10 has been run for each simulated case). A substantial effort has been put into reducing this calculation time, and considerable progress has been made. The final run-times of each simulated scenario will be recorded and presented in sub-section 6.1 of the Results and analysis-chapter, but initial results show roughly a 50 percent decrease. No doubt, further reduction of computation times will be a key point in future development of the model.

Parallelisation is key to reducing computation time. Parallelisation is about utilizing the full potential of the available processing power in this age of multicore processors. For the optimization problems related to our simulations, it means sharing the workload of numerous and/or large LP-problems between multiple processor cores. In a way, what separates ProdMarket from ProdRisk is an extra layer of parallelisation. ProdRisk too has the theoretical capability to calculate larger systems with multiple waterways, but the size of the optimization problem quickly reaches a point where calculation time is unacceptable. This can to some extent be alleviated by using parallelisation; ProdRisk allows for utilization of multiple processor cores. But ProdMarket's added ability to split problems down to the sizes determined by the hydrologically connected waterways, allowing it to run separate optimizations for each one, allows for a second level of parallelisation. Each ProdRisk-problem is now smaller, and can be calculated in parallel. Using ProdMarket on multicore processor setups, each of the ProdRisk-optimized sub-problems are indeed normally run simultaneously, in parallel, in order to speed up calculation times. This has also been the case here. As mentioned, this thesis is largely a continuation of work performed in relation to the project thesis Kyllingstad (2015). This did not, however, utilize more than three processor cores, the number set by the number of waterways simulated. One change in settings, however, has had major impacts on the subject of computational requirements: The number of price periods per week. It has been increased from four, to 16. Put simply, the price periods (also called load periods) indicate how many price calculations are performed for each simulated week – drastically increasing the size of the optimization problem at hand.

The first and most important step in reducing run time of the model, was moving from a small laptop to a more powerful desktop PC. Even on the more powerful computer, however, initial tests with 16 price-points showed unacceptable computation times in excess of 20 days. This meant the change from four to 16 price periods could only be made if major improvements could be made to computation times. The increased processing power had to be utilized more effectively.

The default setting for this thesis was from Kyllingstad (2015). Hence, on the four processor-core laptop, each ProdRisk sub-problem would be solved in parallel, taking up one processor core each. The in this case three area-optimization problems would not complete at the same time, leaving up to 75% of the processing power unused much of the time; utilization of the total processor power was limited. Moving from the laptop to the desktop PC meant exchanging a four-cored processor for an eight-cored one[9]. So on the desktop PC, utilization

[9] Both computers apply an Intel-technology called HyperThreading to allow each physical processor core to appear as two logical cores to the operating system – hence the actual number of physical cores were 2 and 4, respectively.

was even lower: Initial settings meant that at most three of the eight available processor cores were fully utilized. This set the stage for exploring additional options for parallelisation. The following paragraphs discusses the steps taken to increase utilization of available processing power.

Change of LP solver: CPLEX

Both the ProdRisk area simulations and the overall market simulation rely on LP-solvers to solve their respective optimization problems. ProdMarket supports the use of two different LP-solvers. A solver called “COIN” was used in the project thesis. The other alternative, “CPLEX”, requires a license, but is generally thought to be faster; it can be up to three times as fast as “COIN” on certain problems (Henden, 2015b, p. 7). For this thesis, a licence was acquired in order to enable CPLEX. CPELX was hence used for all simulations.

Two-layer parallelization: MPI, allocation of threads

As discussed previously, ProdMarket runs separate ProdRisk-simulations for each waterway. This constitutes a first layer of parallelisation in the calculation. When run on a computer with more processor cores than simulation areas, an opportunity arises to also share the workload of each waterway between several cores. This requires allowing a single optimization problem to be split between several processes. This is achieved through enabling the MPI-setting in the ProdMarket run settings. When MPI is enabled, two-level parallelisation becomes available.

Hence, when ProdMarket starts MPI-enabled ProdRisk-calculations for each of the system’s waterways, it has to decide how to allocate the available processor cores between each ProdRisk-instance. Ideally, one would want all sub-problems to finish simultaneously in order to minimize total run time - Optimization of all waterways have to be completed before the results can be combined in the subsequent market optimization. This means that the model has to make a qualified guess of which areas will require the most computational power. The code sequence that does this allocation of processor cores between the simulated waterways has some limitations. It gives an approximate value of the areas’ relative computational requirements based on the number of hydropower units in each area. It does not, however, separate between the different types of hydropower units; a “unit” can be anything from a gate, to a reservoir-less river-intake, to a reservoir with accompanying production plant (SINTEF, n.d.-a, p. 9). It is likely that some types of units introduce more flexibility and computational stress to the calculations, and hence should be weighed more heavily. Moreover, the size and complexity of the optimization problem is not fully described only based on the number of units it encompasses; the ways in which the hydropower units are hydrologically connected is vitally important. The exact impacts of units and their interconnections on computation times are not clear, however, and would require further research.

In practice, on the three-area data set used in this thesis, the default allocation of processor cores did not successfully match calculation times between the areas. Therefore, the code was modified for the purpose of this thesis to bypass the automatic allocation and manually set the number of processes running per area-simulation - The modification is shown in Figure 9 below. This implicated a key change: Actual results from test-runs were used as scaling factors for the fixed allocation instead of a guess made in advance. Trial runs of single iterations were used to calculate computation time per process: Numedal, which seems the most demanding waterway, calculated at roughly 0.6 ProdRisk iterations per hour per processing thread, Otra at 0.7 and TEV significantly faster at 1.5.

```
#-------------------- Setter manuelt antall kjerner! ---------------------VBK
        antKj[0] = 5 #Numedal
        antKj[1] = 4 #Otra
        antKj[2] = 2 #TEV
        print('\nKjoerer ProdRisk med foelgende antall kjerner per omraade:\n')
        for i in range(0,3):
            print('%s: %s\n' %(Area['NAME'][i],antKj[i]))
```

Figure 9 - Source code allowing manual allocation of processing threads.

Now, having a good idea of the relations between the waterways, the problem was then to find a set of numbers of processes that would yield similar fractions for all three sub-problems. This was achieved through using 11 processes allocated as follows: 5 for the "Numedal" waterway, 4 for "Otra" and 2 for "TEV". The estimated number of calculated iterations per hour would now be $0.6 \cdot 5 = 3$ for Numedal, $0.7 \cdot 4 = 2.8$ for Otra and $1.5 \cdot 2 = 3$ for TEV. With all three numbers now in the same range, the waterways were set to calculate and complete at similar speeds. The exact calculation speeds, however, would be slower than three iterations per hour – closer to two as it turns out. This is mainly due to the PC performing the calculations having "only" eight cores as opposed to the number of processes started, which was eleven. Increasing the number of processes above the number of cores secured two things: Full utilization of available processing power, and more freedom in terms of weighing the area sub-problems according to individual calculation requirements. Depending on whether the computing PC is used for other tasks, it may not always be desirable to overload the processor in this way – one may want to preserve some processing power for running other applications effectively. As for maintaining a near-perfect ratio between the sub-problems, it becomes a task of balancing time lost due to overhead and time gained due to simultaneous completion of the ProdRisk problems. Overhead in this respect is the processing power used for coordinating the parallel processes. It represents a loss in calculation efficiency, and increases as the level of parallelisation increases. Practical trial-and-error results indicate relatively moderate increase in overhead up to the five processes per ProdRisk optimization problem used in this thesis (for the Numedal waterway). This indicates relatively good scalability in terms of number of processes and cores.

An important observation in terms of allocation of parallel processes is that the solution introduced here should be quite easy to implement into the model itself. Basing the first outer-loop iteration on the current allocation method, or an updated version of it, the results could then create a basis for an improved allocation in the subsequent iterations. The ProdRisk run-times from the first ProdMarket iteration could be recorded and used to minimize run-time of the later iterations.

To briefly sum up on the discussion on computational time, considerable progress has been made. ProdMarket (and ProdRisk) holds a number of options that allow for increased calculation efficiency. Starting out with estimated calculation times well in excess of 20 days for a 10-iteration simulation run, the time has been more than halved, to around 10 days. The final computation times will be recorded (or rather, calculated, a subject which will be discussed later on) and presented in Section 6.1.

Chapter 5 The simulation cases

Hydropower scheduling software such as ProdMarket are only as good as their input data. In computer science, the phrase "garbage in, garbage out" is commonly used – poor input yields incorrect output, no matter how good the model. In power system analysis, it serves to show the importance of a good system description.

This chapter tackles the challenge of creating robust data sets that is capable of producing good results. If the results are to provide any true insights on the present and future Norwegian power system, our data sets must in some way display at least some of the same dynamics. Hence, this chapter builds directly on the insights from Chapter 2. First, it introduces the default data set which is to be modified to create our simulation cases. Some methodology regarding modelling is discussed. Then comes a series of subsections that motivate, then build and present, the three simulation cases studied in this thesis. The first case is based on present conditions, whereas the other two are future scenarios. The simulation scenarios will mainly be adjusted along the following axes:

- Hydropower **production capacity**
- **Pumped hydroelectric storage** (PHES)
- **Demand** level in Norway
- **Wind** power in Norway
- Size of **interconnectors** to UK and Germany
    - UK **offshore wind** and demand levels to match interconnection
    - German **solar power** and demand levels to match interconnection

There are a number of other aspects that could have also been explored, but limitations had to be made as to what is included in the scenarios; the above are considered particularly useful for highlighting key aspects of the present and future power system. Availability of thermal power is one of the factors that are kept constant. This could perhaps seem unnatural as this thesis sets out to increase renewable share, but the simple reason is that, with zero marginal cost, the added renewable power will automatically replace thermal power in our system. As for pumped hydro, the focus will be on reversible pump turbines, not on specialized pump stations. The latter form of pumping does not introduce any fundamentally new aspects in water handling, and is as such not considered for our simulation cases.

The future scenario cases of this thesis are mainly derived from three sources; the first is strictly qualitative, the other two is quantitative as well. The sources are as follows:

i. SINTEF and NTNU's HydroBalance project (Sauterleute, Wolfgang, & Graabak, 2015).
ii. ENTSO-E's (2015a, 2015b) forecasting report "Scenario Outlook & Adequacy forecast".
iii. Statnett's (2015a) grid development plan.

Note again that although an effort has been made to choose realistic cases, based on discussions or assumptions of the current and future Norwegian and European power system, the cases should be considered illustrative examples. Particularly interconnection to the European continent is handled in a very simplified manner due to the limitations in ProdMarket's handling of interconnection. Nonetheless, the simplified model is considered illustrative. Subsection 5.2.2 discusses this.

5.1 Data set

The data set used as a basis for this thesis consists of three watercourses with 50 modelled units – a "unit" being a gate, a river-intake or a reservoir, with or without a production plant (SINTEF, n.d.-a, p. 9). The three watercourses are named "Numedal", TEV and "Otra". The inflow and storage volumes and production capacity of each waterway and the system as a whole is shown in Table 10 below.

Table 10 - System properties of the modelled system, per waterway.

	Units	Reservoir capacity [Gm^3]	Inflow [Gm^3/year]	Production capacity [MW]
Numedal	17	0.93	3.18	610
TEV	12	1.38	3.22	535
Otra	21	1.95	4.47	820
Total system	50	4.26	10.88	1965

From Table 10 we see that the Numedal and Otra waterways are somewhat larger than TEV; optimizing these two also required significantly more processing power, as discussed in section 4.3.5. In terms of reservoir capacity, however, Otra is the largest followed by TEV. Inflow is also largest in Otra, while TEV and Numedal have roughly equal amounts. In other words, Numedal has the least reservoir capacity compared to inflow. This is also evident from how the waterway is operated: Out of the three, Numedal has the largest seasonal variations in magazine levels (water handling in Numedal was plotted in Figure 4 during Calibration of EMPS, section 4.1.1). As we will look at PHES later on, it is worth noting that the default data set has a small pump of 19 MW in the Otra waterway. This pump is not discussed in detail, as it represents the "traditional" form of pumping; it generally pumps all available inflow, to improve water usage. Refer to Section 2.2.5 for an explanation of this form of pumping, and Chapter 4 for a description of how pumps are handled in the models.

Based on simulation results, the total system has a combined mean energy inflow to its magazines of roughly 9.4 TWh/year, of which simulations show that the system is able to utilize around 8.9 TWh/year[10]. When measured in energy, the inflow is the amount of energy the system is able to produce from the inflow volumes, hence it varies between reservoirs and from system to system. On the load side, our unchanged data set has contractual obligations to deliver a total of 10.58 GWh/year. Table 11, below, lists all firm demand contracts in the data set. This puts the data set at an energy deficiency of roughly $10.58 - 8.90 = 1.68$ TWh. Note that the load levels will be modified later on. Nonetheless, this means that the risk of rationing is high, and that additional energy will have to be either produced by thermal units or imported if the power obligations are to be met. The curtailment cost is set to 445 øre/kWh, but the data set also allows for a stepwise form of curtailment through repurchasing of contractual obligations (this models how some loads can be interrupted at a lower cost than others). The data set includes 50 years of historical inflow data, from 1931 to the end of 1980. With a simulation period of three years, this means that each inflow year is used in three inflow scenarios.

[10] "mean inflow" and "usable inflow" are based on ProdMarket's results in Table 20, p. 85. "mean inflow" is the inflow in the table, divided by three. "usable inflow" is here calculated as a third of the sum of delivered hydropower and increase in magazine level (end magazine subtracted start magazine). Numbers are rounded due to the innate inaccuracy of such numbers based on simulations.

Table 11 – Overview of firm demand contracts in default data set.

Contract name	Location (EMPS)	Total amount (GWh)	Yearly amount (GWh)	Yearly profile (load profile)	Weekly profile (power profile)
Alm. Forsyning-Numed	Numedal	6210	2070	PL_ALM. FORSYNING	PE_ALM. FORSYNING
Industri 95-Numedal	Numedal	2775	925	PL_INDUSTRI 95	PE_INDUSTRI 95
Fastkraft progno-TEV	TEV	6300	2100	PL_FASTKRAFT PROGNO	PE_FASTKRAFT PROGNO
Ko.kr skjøk sommer-T	TEV	27	9	PL_KO.KR SKJØK SOMMER	PE_INDUSTRI 95
Ko.kr skjøk vinter-T	TEV	40	13	PL_KO.KR SKJØK VINTER	PE_INDUSTRI 95
Ko.kr Grytten sommer	TEV	5	2	PL_KO.KR GRYTTEN SOMMER	PE_INDUSTRI 95
Ko.kr Grytten vinter	TEV	13	4	PL_KO.KR GRYTTEN VINTER	PE_INDUSTRI 95
Ko.kr Norddal sommer	TEV	52	17	PL_KO.KR NORDDAL SOMMER	PE_INDUSTRI 95
Ko.kr Norddal vinter	TEV	111	37	PL_KO.KR NORDDAL VINTER	PE_INDUSTRI 95
Fastkraft-Otra	Otra	9900	3300	PL_FASTKRAFT	PE_FASTKRAFT
Fastkraft progno-Term	Term	6300	2100	PL_FASTKRAFT PROGNO	PE_FASTKRAFT PROGNO
Total		**31733**	**10578**		

Table 11 shows all contracts in the default data set. These contracts make up the so-called “firm demand”. Firm demand is demand that is modelled as inelastic to price, and hence “must” be met (if it cannot be supplied, then repurchasing and rationing is also available). The second column shows what area the contract belongs to in the EMPS implementation. In ProdMarket, all the local contracts are part of the local area in addition to the Hode area. Each contract has a set demand, in Giga-Watt-hours per year, and follows two different profiles.

One is the yearly profile, also called a load profile, which describes how the load varies from week to week over a year. The second is a weekly profile, called the power profile; this detail how the load varies from one hour to another within a given week. The hourly resolution will, as discussed in the paragraph on price periods, be summed and averaged over the sequence of hours constituting a single price period (Section 4.3.4). In the following case development, most of the contracts in Table 11 will remain unchanged. Only the last contract, "Fastkraftprogno-Term" will be edited where applicable to the case at hand, to model decreased demand in areas surrounding the modelled waterways.

5.2 Modelling

The analogy that our system is a miniature version of Norway will be used to visualize the results and to motivate the changes made to the data set in the different cases. Comparing our system's size to the entire Norwegian system, our system produces roughly $\frac{9.8\ [\mathrm{TWh}]}{130\ [\mathrm{TWh}]} = 7.54\ \%$ of the size in terms of delivered hydro energy. The analogy and the scaling factor linking our system to the overall Norwegian system will be used throughout implementing present and future scenario cases into the data set. The intention is that the simulation cases studied will hold a level of realism that allows for insights into production planning of the Norwegian system. Nonetheless, the main focus remains on analysing ProdMarket as a decision support tool and to compare it to EMPS, not on predicting the future of the Norwegian power system. The cases and results remain illustrative examples, not accurate reproductions, of the full-scale Norwegian system.

Note, for example, that some sizes are scaled to fit the size of our model, whereas some are not. Since the installed storage and production capacity of each hydropower unit in our system is in fact based on the existing units in parts of the Norwegian grid, they are in a way out of scale compared to the total system size if the system is viewed as scaled model of Norway.

Due to the way our models are tuned towards hydro power, we will mainly discuss energy balance by comparing load to hydropower production, not total production including thermal power. This is because exchange between areas are not currently implemented in ProdMarket, and as such the model does not explicitly differentiate as to where thermal power comes from (other than the name of the thermal production contract describing what it represents). The thermal power in our data set, for instance, includes some production inspired by Swedish thermal plants, some by Norwegian plants in the studied waterways and other by Norwegian plants in other areas. Hence, although contracts representing sizes such as import and export are available in the results, they are not directly comparable to real-life import and export levels.

A group of variable contracts (not firm, as the demand contracts) called “interruptible loads” represent a number of different options for buying and selling power that is price elastic. It includes import and export to external markets (outside of the simulated area), loads that can be substituted (e.g. electric heating), interruptible industrial loads, cost of thermal power in the system, spot-market transactions, repurchasing and rationing (SINTEF, n.d.-b, pp. 8, 119). Our data set holds a total of almost 150 such price-dependant contracts.

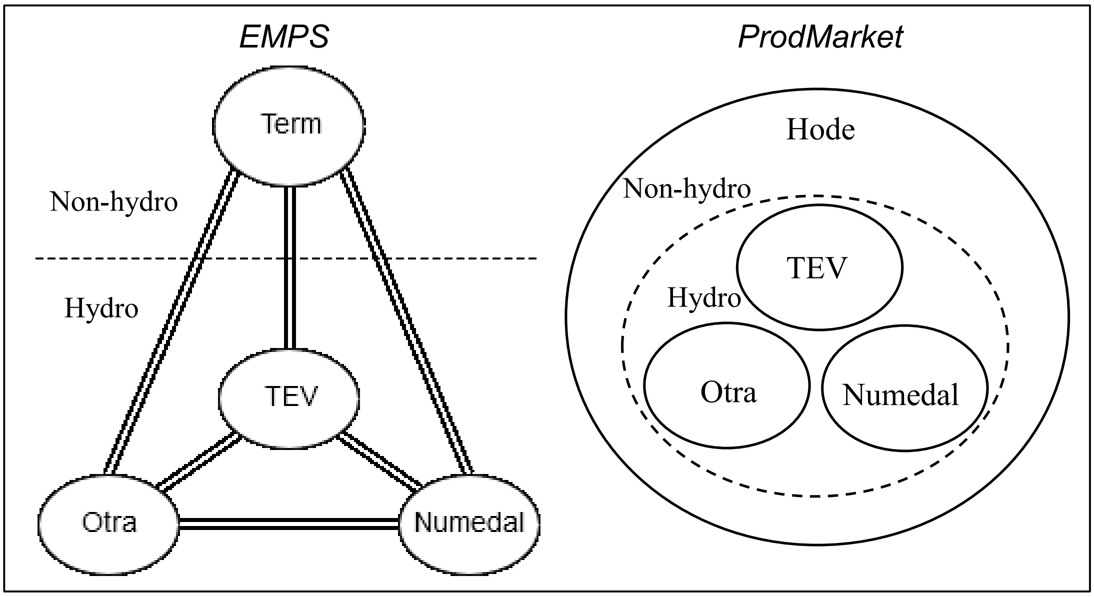

Figure 10 – Implementation of data set in EMPS and ProdMarket.

Implementation of the data set is somewhat different between ProdMarket and EMPS. Figure 10 above is an attempt at highlighting the similarities and differences. Since EMPS supports modelling of multiple areas, each waterway is treated separately, but with connections between the areas. In our case, the interconnections have been set to infinite. In practice, “treated separately” means that each waterway is viewed, opened and edited in separate user interfaces. In addition, there is a fourth sub-area named “Term” (for “thermal”), that represents “the outside world”, i.e. everything not part of the local areas. The Term area holds additional non-hydro power sources, both thermal and renewable, additional load contracts, and contracts representing connections to other countries, amongst other things. The ProdMarket implementation is slightly different: First of all, there is no “Term” area, but an area called “Hode” (as in “head”). This is what the overall market simulator bases its calculations on. Unlike Term, it holds not just information of the outside world, but all detail of the internal system as well. This reflects how the three local areas are not just individually optimized, but are also included in the overall system simulation in full detail. As a result, changes made to the data set that is to be included in both the local and global simulation, has to be implemented in both Hode *and* their respective sub-area.

The default data set does not incorporate any additional renewable production apart from the modelled hydro system. The simulation cases of this thesis, however, will introduce two new renewable energy sources, and explore two different methods of implementation. The technologies are solar power and wind power. The implementation methods relate to "Norwegian" power and "continental" power, respectively.

5.2.1 Implementation of wind in Norway

This discussion is directed towards wind power, as it is currently the most relevant for the Norwegian system, but generally applies to all intermittent power sources.

Implementation of renewable power into the EMPS and ProdMarket models is pretty straight forward once the input is prepared. In ProdMarket, you simply add input files to the directory of the data set named "vindtime_X.v30", where X starts from 1 and increases for each file added. The file is then included in the data set by specifying the "-wind" option when running the market simulator from the ProdMarket script. As previously mentioned, however, the wind energy will not show up anywhere in the user interface (section 4.3). In EMPS, the EOPS user interface is loaded for a specific area, which then has options to add the wind power input files to that area. For EMPS, the wind power will show up in results.

The input files are binary files (they can be converted from spreadsheet-files using the "Tilsig" module) that specify power production within a series of time steps. More specifically, they set the amount of *energy* delivered (MWh); The resulting average power output can be calculated based on the time step (MWh/h = MW in this case), but the underlying installed or maximum production capacity can only be estimated. In our case, the input files hold hourly production levels for 75 "weather-years" (since we are simulating 50 inflow-scenarios, the first 50 years will be used). Each file could represent anything from a single unit's production to the aggregate production of entire countries. Our Norwegian wind files are based on the production of wind power in southern Norway.

In essence, the models handle the renewable production input files are handled as if they were negative demand series (Henden, personal communication, 2016): Before the models try to match production to firm demand levels, they subtract the wind power production from the demand. Hence the renewable energy induces no direct cost for the system, but directly affects load levels, hence reducing system operating costs.

5.2.2 Interconnection with EU: UK offshore wind and German PV

Norway is connected to many of its surrounding countries by numerous overhead, buried or subsea cables and lines, both AC and DC. As previously mentioned, ProdMarket does not support interconnection between separate grid areas, as EMPS does. For the future scenario cases, however, it would be useful to have a method of modelling the some of the assumed new renewable generation in the European power system – in addition to the already discussed Norwegian wind. In the EMPS model, we could have created a separate area that represented each neighbouring country or area connected to our model, complete with loads, production and transfer capacities, but when comparing to the current version of ProdMarket, that option is not available to us.

Import and export is already, to some extent, incorporated into the data set, through “interruptible load” contracts representing import and export (mostly to Sweden and Denmark). In other words, the implementation does not have to fully incorporate all aspects of cross-country interconnection, as the basic aspects of “classic” thermal import and export is already built into the data set. Hence, we accept approximate methods that model the specific system impacts of the “new” renewable interconnection to EU. Specifically, we would want to study the effects of balancing German PV and British offshore wind.

The chosen method is as follows: Subtract German load from the German PV production, and British load from the British wind production, so that the resulting combined load and production series mimics the positive and negative flow on respective interconnectors. The new series will represent the need, i.e. the demand, for transfer capacity; it will henceforth be referred to as a *transfer series*. A key aspect is that the peak import and export hours of the resulting series is then cut down to the chosen interconnector size. A schematic of the solution, as created by A. L. Henden, is seen below in Figure 11.

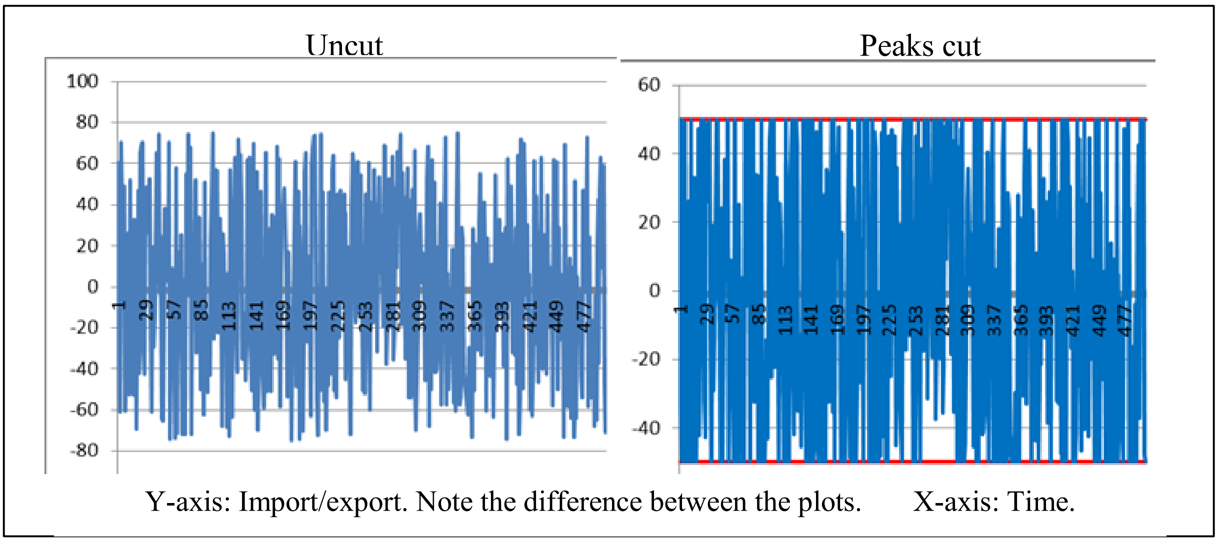

Figure 11 – Schematic of combined load and production series. Left: Uncut. Right: Cut. [11]

For the sake of simplicity, our implementation of the interconnection series will be energy-neutral, meaning that the import and export balances out over the year. The hydropower system's energy balance is taken care of in other ways. The German and British production profiles are scaled to fit future scenarios for power system development. The load profiles are also scaled, and are subtracted from the production profiles so that only the hourly difference (whether positive or negative) is visible to the system. The peaks of the resulting "transfer demand"-series are then cut down to the transfer limit of the cable. The *transfer series* is then added to the model as a production profile in the same manner as for the Norwegian input files for wind power. Unlike it, though, it has no net energy contribution over the (average) year: The load series are scaled so that the sum energy is negligible. However, even though the constructed combined load and generation series are energy balanced over 50 years, each year introduces a smaller or larger deviation from this balance (similar to how inflow years fluctuate, so do weather-years for wind and solar production).

In this case, the UK offshore wind series is said to represent production in the "Dogger Bank" area, and the German PV series represent aggregate production from southern parts of Germany. Both demand and production is given in hourly numbers over the course of a year. The German PV and British offshore wind is given for all 50 years of the simulation period, while the demand is given as a yearly profile that is used over for each simulated year. Transfer demand is hence calculated on an hourly basis: The abroad load level for each hour of every year is subtracted from the corresponding hourly production level. Where the

[11] As illustrated by Henden (personal communication, 01.03.2016).

resulting series is positive, it indicates a power surplus, and where it is negative, a power deficit. In the real world, the power surpluses or deficits could have then been balanced either by local change in generation levels abroad, or by energy transferred to and from Norway through interconnectors. Basic supply-and-demand-dynamics would ensure that European prices rose in periods of power deficit, and lowered in times of energy surplus. If the available balancing capacity is limited, or expensive, price fluctuations will increase. We do not have this option: Whatever is input into the model as a production series is fixed (there is no price elasticity), so the flow on the interconnector is fixed. However, assuming that balancing from Norwegian hydropower is amongst the cheapest sources of balancing, it would have been used before most other sources of balancing (Once infrastructure such as interconnectors are built, production regulation of wind power has little direct cost). As such, we can at least motivate the assumption that power surplus and deficit in Germany and the UK will be covered by interconnectors when possible.

Given limited interconnection between two power grids, their respective price levels will generally differ. In the case of the Norwegian and European power grids, the size of the systems far outweighs the available transfer capacities. Hence, cables rarely offer enough capacity to even out the price differences between countries. This means that it is normally economical to fully utilize the available transfer capacity to maximize economic gain. Following from this, continental power cables should generally see high usage, whether the flow is positive or negative: In periods of import, interconnectors will generally import as much as possible; in periods of export, interconnectors should export to their full potential.

In regards to transfer series and transfer capacities, the subject of system scale is an important consideration. In this thesis, the available transfer capacities between Norway and the UK and Germany is scaled down according to a scaling factor of each case. As discussed, the scaling factor represents the relative size of the modelled hydropower system as compared to the Norwegian system. It should be noted that scaling down the modelled transfer capacity according to our system size will inevitably affect the realism of the dynamics between the transfer capacity and our hydropower system. First off all, using a scaling factor based on the entire Norwegian system implicitly assumes that all of the Norwegian power system is available to balance power flow fluctuations on interconnectors. This is not necessarily the case in periods of limited internal transfer capacity in the Norwegian grid, when balancing of overseas interconnected loads and generation will have to take place in the regional grid in proximity of the point of interconnection. This is, however, on the long term, self-regulating, in that interconnectors will only be allowed built or utilized to an extent that their capacity can be balanced properly. On the other hand, *not* scaling down the transfer capacity and foreign load and generation on the other side, is a much worse alternative. The theoretical yearly energy transfer would then be 12.2 TWh as compared to our system's annual production of roughly 8.9 TWh. Tests were run to check viability of such a solution, and results indicate enormous price fluctuations as the direction of flow on the interconnectors change – taking the hydro system almost instantly to and from situations of extreme deficiency to power surplus. Prices would frequently drop from the rationing cost of 445 øre/kWh to zero in a matter of hours. This simply indicates that a model of the entire Norwegian system is required to balance the massive changes of a full-scale interconnector.

5.3 Base case - Present situation

This subsection is aimed at developing a simulation case that represents the present situation in Norway. The subsequently presented future scenarios will then expand on this case. Hence, the main objective of the "Base case" is to be a benchmark for future reference. For now, only subtle changes are made to the data set; the more substantial changes will be introduced in the future cases. Specifically, firm demand level is decreased somewhat, along with the addition of a modest amount of Norwegian wind power. Note that PHES is not considered for this case, even as the regression analysis showed that our modelled system had somewhat less pump usage than the Norwegian system. This is because most of the current pumping in the Norwegian power system is assumed to be seasonal pumping in specialized pump stations, not reversible pump stations.

All cases are run with the same run settings. For the run settings used in this case and the other, refer to sections 4.1.1 and 4.3.1 for EMPS and ProdMarket, respectively. Each model's respective settings are also listed in Appendix A and B.

Picking up the thread from Chapter 2, the data set is to be tuned towards the key characteristics of the Norwegian power system as presented there. This time, the regression analysis results from Appendix C are scaled down and used to quantify the wanted power mix in our Base case:

Table 12 - Wanted energy mix, Norway. BaseCase.

Energy source	% of prod.	TWh	GWh
Hydro	95,29	8,9	8900
Thermal	3,36	0,31	314
Wind	1,36	0,13	127
Total	100,01	9,34	9340

All data in Table 12, above, are scaled based on our data set's approximate yearly hydro production, 8.9 TWh. Note that the rest of the table is calculated to a higher degree of accuracy than this number, which is limited to only two significant digits. Scientifically, this is not strictly correct, but it can be allowed as long as the results are not taken too literally. And as has been commented numerous times already, we are already aware that simulation results, no matter how good, are not perfect representations of the real world. There is also a considerable innate inaccuracy in the regression results. All aspects of the Norwegian power system are massively affected by the yearly inflow variations that control the hydropower production. And the yearly variations are considerable; take the recorded hydropower production in the years 2011 through 2013, for example: Table 29, Appendix C, shows how production increased by more than 21 TWh from 122 TWh in 2011 to 143 TWh the following year. In 2013, production was back down to a more average level of 129 TWh. Hence, the regression analysis has some uncertainty. To illustrate: The analysis returned 130 TWh as an approximate of the true mean inflow in 2014, and a total system production of about 138 TWh. But the numbers from the production mix analysis would mean that the mean hydropower production in 2014 was $0.9529 \cdot 138 \approx 132 \neq 130$. We will stick with the number requiring the least amount of calculation, so 130 TWh is kept as an estimate.

Out of the three energy sources specified in Table 12, only one is given directly as input to the simulation models: Wind. So this is what we will focus on quantifying. Hydro production is also fairly constant (at least it should be in in the long run) for a given set of inflow levels and production units. The amount of thermal production is not considered explicitly, but is affected by the other two. As discussed in the previous sections, thermal power and other variable power is handled as price-dependant power, controlled by the simulated power price. As the models search for cost minimization, the amount of thermal power bought is in practice largely (but not solely, factor such as production capacity also come into play) controlled by the energy balance of the system. In this respect, the energy balance is the balance between the free renewables, hydro and wind power, and firm demand. So demand is the second size which we will discuss.

Compared to the future cases then, the following aspects is **not** considered relevant in the Base case:

- Hydropower **production capacity**
- **Pumped hydroelectric storage** (PHES)
- Size of **interconnectors** to UK and Germany; UK offshore wind, German PV.

The first is considered not relevant because our system's balance of production capacity and storage is based on actual production plants. Assuming that the three studied waterways are somewhat representative, the relation should be realistic for Norway as a whole as well. As for the other two aspects, both is present in the current power system. One could say that due to their limited penetration, they are negligible, but there is also another rationale for why they need not be relevant for the Base case: The future scenarios are mainly focused towards highlighting the *changes* compared to the Base case. So it is not crucial that the current impacts are non-existing, as long as the *changes* introduced in the future simulation cases are based on actual *changes* in the power system. And there is little doubt that the planned German and British HVDC interconnectors will affect the power system on both sides.

Norwegian wind power

A wind series is added to the data set, as described in the previous section. As for the amount of wind energy added, note that we will stick to the production mix numbers from Table 12, as these all cover 2014. We will not use the 2015-figure from our discussion of wind in Subsection 2.3.1. So the wind series is scaled to contribute 127 GWh of energy per year, as per Table 12 above. Scaling up to the Norwegian system size, this means that we have estimated the 2014 mean wind energy production in Norway to $0.127[\mathrm{TWh}] \cdot \frac{130}{8.9} =$ 1.89 TWh (as opposed to the 2015 figure of 2.22 TWh). Just over 0.1 TWh is relatively little compared to the system's estimated hydro production of 8.9 TWh. It is plausible, however, that there are years where wind power could contribute significantly more, or less, than this level. Analysing all 50 years of wind input used, the largest and smallest observed power contribution is 155 GWh and 101 GWh, respectively. So the 50-year variation lies within roughly ± 20 percent. This does not contribute a whole lot at this stage, but could be relevant as more wind is added to the power system.

The equivalent installed wind capacity can only be estimated from the energy production numbers based on estimated usage times. Using the average usage time in Norway in a normal year (as per 2015), from Table 2, page 12, the calculation is done as follows (for Norway and for the modelled system, respectively):

$$P_{wind,estimate,2014}^{Norway} = \frac{W_{yearly}}{T_{Usage}[\mathrm{h}]} = \frac{10^6[\frac{\mathrm{MWh}}{\mathrm{TWh}}] \cdot 1.89[\mathrm{TWh}]}{2692[\mathrm{h}]} = 702[\mathrm{MW}]$$

$$P_{wind,estimate,Basecase}^{model} = \frac{1000 \cdot 127[\mathrm{GWh}]}{2692[\mathrm{h}]} = 47.2[\mathrm{MW}]$$

Compared to the installed hydropower generating capacity of 1965 MW, the total wind production constitutes a mere 2.5%. It is once again clear that wind energy really is a minor factor in the current Norwegian power system.

Demand

The demand level is to be adjusted to match the current Norwegian demand level, as compared to the size of its hydropower production. As previously mentioned, hydro production is used as the scaling factor as this is the easiest to compare between our model and the Norwegian power system. From the introduction to Chapter 2 we already know that, based on the regression results, the Norwegian hydropower production roughly matches the demand level in a normal inflow year: Hydropower production was estimated to 130 TWh, so was the demand level. In essence, this is what is sought after for the modelled system as well.

Due to a minor calculation error during implementation, however, the actual power balance of the Base case is as follows: Roughly 8.9 TWh of hydropower and (exactly) 0.127 TWh of wind power is to supply 8.83 TWh of load. In this respect, the actual load is 0.07 TWh, or 70 GWh too low, to maintain an energy balance between hydropower and demand levels. The error is, however, negligible. Moreover, it is plausible to be within the array of possible values for the actual hydropower production in our system (this entity is, as previously discussed, a result of simulations, and as such varies somewhat between models and between simulation cases). Including the wind power, the modelled system is now at a power surplus just by using renewable power: Hydro and wind power is estimated at a combined output of roughly 8.91 TWh per year, versus a firm load of 8.83 TWh.

In practice, the new load level represents a considerable decrease from the default data set, which, as was discussed in Section 5.1, holds roughly 10.58 TWh of load. $10.58 - 8.83 = 1.75$ TWh of load is removed from the data set. The below table shows the new size of the demand contract that where this change is implemented: The firm power demand contract in the "Term" area. In ProdMarket, the change is performed in the "Hode" area.

Table 13 – Size of demand contract "Fastkraftprogno-Term", Base case.

	Total amount (GWh)	Yearly amount (GWh)
Default data set	6300	2100
Base case	1050	350
Difference	-5250	-1750

Base case implementation settings are shown in Appendix E. As the Base case is now created, it is time to shift focus towards the future scenarios.

5.4 Scenarios for the future

This section holds a discussion ultimately aimed at quantifying future scenarios. The challenge is that the future is uncertain, stochastic, while calculations require discrete cases. Of course, care can be taken in choosing the most likely outcome of the uncertain future. But for systems as complex as the power system, which intertwine with society on national and international politics, and with nature in terms of climate and weather, the outcome of one factor is sure to affect multiple others. Use of scenarios can, to some extent, compensate for this. But the number of scenarios is often limited due to practical reasons, such as computation time and work hours spent analysing, as in this thesis. The task is, in essence, to cover as much of the outcome space as possible, with as few scenarios as possible.

Scenarios allow for creating multiple futures, of equal or differing probability, and then, if necessary, weighing their relevance based on their assumed outcome. It is commonly used for complex problems, e.g. climate change; climate change also directly and indirectly affects the power system, as discussed in Subsection 2.2.1. A common rationale behind working to reduce climate change goes like this: "We do not know the full extent of the costs of climate change, but the costs of the pessimistic scenarios are so large that we should act now, irrespective of the true probability that it should occur". In a way then, analyses based on scenarios incorporate an innate form of risk management: Risk is commonly evaluated as a product of probability and consequence – one may be small if the other is sufficiently large. This means that if we cover two bases, we are at least a step in the right direction: Firstly, look at what is most realistic, or probable; it is important because it is likely to happen. Secondly, identify what could cause deep changes; it is important due to its far-reaching consequences. Put simply, this two-way approach is what led to the two future scenarios used in this thesis.

So, what futures are to be studied, and what do they bring? The two scenarios are chosen amongst four main qualitative scenario descriptions from a joint SINTEF and NTNU project called the HydroBalance-project. The two are then quantified using ENTSO-E and Statnett's numbers, along with guesstimates where no data is available. We will look at the period around year 2025, as it is well covered by the quantitative scenarios.

5.4.1 Qualitative scenarios: The HydroBalance project

The HydroBalance project is directed at studying the challenges related to using the Norwegian hydropower system for large-scale balancing and storage (Sauterleute et al., 2015, p.5). Hence, their scenarios are characterized in terms of how a certain set of factors affect the potential for regular and pumped storage balancing.

The creators of the HydroBalance-scenarios differentiate between future factors that are controlled by Norwegian decision makers, and other uncontrollable factors. The controllable aspects are called *options* – a set of options forms a *strategy* set by Norwegian decision makers. Uncontrollable factors, such as EU member states' policies, are simply called *uncertainties* – a set of outcomes of these uncertainties constitute a *future*. A *scenario* consists of a strategy undertaken in a given future. As part of the HydroBalance project, four strategies and four futures were identified and used to create a four-by-four matrix of 16 scenarios. Of these, four particularly relevant scenarios were selected.

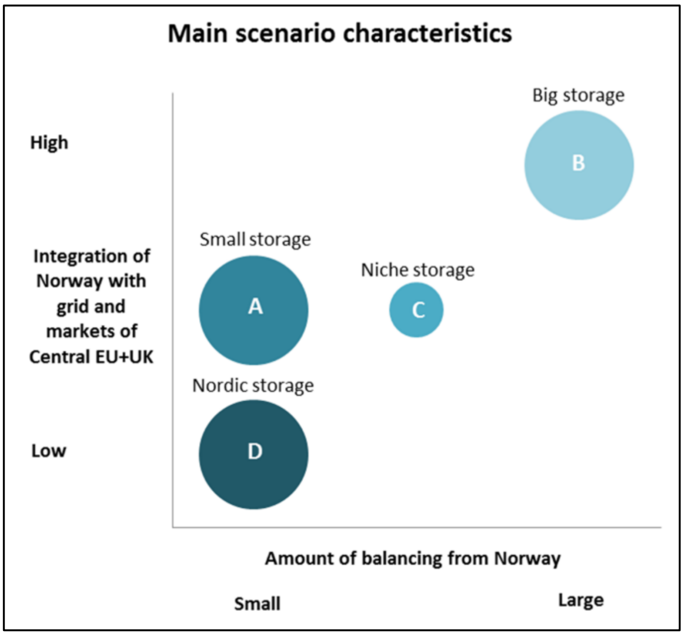

Figure 12 – Main HydroBalance-scenarios' characteristics.[12]

Figure 12, above, illustrates how the four chosen HydroBalance-scenarios relate to each other; amount of power balancing capacity in Norway on one axis, and the degree of integration between Norway and Europe on the other. Moreover, the size of the "bubbles" indicate what time scale the balancing covers: Small bubbles indicate long-term balancing only, whereas the larger bubbles indicate balancing on short as well as long time scales.

Starting with bubble A, called "Small storage", it is placed in an environment with medium grid integration and only a small amount of balancing. It does, however, cover balancing over all time-scales. Bubble B, "Big storage", involves high integration, large balancing capacity and both short and long time horizons. The third bubble, bubble C, represents only long term balancing, hence its name "Niche storage", in a future of both medium grid integration and balancing capacity. Lastly, the "Nordic storage" bubble, bubble D, uses hydropower for balancing on all time-scales, but with limited capacity and grid and market integration. The first two, A and B, are chosen for this thesis. Looking back at our discussion of scenario analysis in general, Scenario A – "Small storage" covers the base of being the most likely, whereas Scenario B – "Big storage" introduces the largest changes and hence the largest potential consequences. Scenario A is considered the most realistic as it assumes moderate developments on most areas, Scenario B the most impactful as it incorporates the largest amount of new energy technologies (and holds the largest potential for pumped storage). The

[12] Reprinted from "Scenarios for large-scale balancing and energy storage from Norwegian hydropower" by J. F. Sauterleute, Graabak, & Wolfgang (2014, p. 9). Reprinted with permission.

following sections will explain the details of each of the two scenarios and go through the process of quantifying each one into a data set ready for simulation.

5.4.2 Quantitative scenarios

With inspiration from HydroBalance as to what the future scenarios may hold, we turn to ENTSO-E and Statnett for help in turning the visions into quantifiable simulation cases. Where the ENTSO-E and Statnett's scenarios differ, we will mostly rely on the Statnett scenario, as it is more focused on Norway in its analysis.

ENTSO-E's (2015a, 2015b) "Scenario Outlook & Adequacy forecast"

ENTSO-E has developed two scenarios, of which we will use only one: The "Best Estimate Scenario". The best estimate scenario – constituting what is considered the most likely outcomes on a range of parameters – will be used as a reference for «moderate» and «medium» growth in the HydroBalance scenarios. ENTSOE'S scenario dataset is quantified for the years 2020 and 2025 – we will use the 2025 figures. For each year, the numbers are given for January as well as July. This is presumably used to study how changes in the available installed capacity during the course of a year could affect the power system. In our analysis, however, it is sufficient to neglect the impact of maintenance and other variables. We will use the highest number and assume that the available capacity is stable throughout the year. The main figures of interest, for us, is as follows:

Table 14 – Key power system figures for 2016 and 2025 from ENTSO-E.[13]

	Unit	2025
Hydropower capacity	GW	33.8
Germany: Sun capacity	GW	54.0
UK: Offshore wind capacity	GW	25.7

Statnett's (2015a) grid development plan 2015

Statnett's grid development plan looks at Norwegian power system up to twenty years ahead. It is, in essence, a result of a transmission system operator's need to plan for the future. Most numbers are given for 2020 and 2030, we will simply interpolate between the two to get what we are interested in.

[13] Data from ENTSO-E's "Best Estimate Scenario" in «Scenario Outlook & Adequacy Forecast 2015» (2015a, b).

Yearly electricity demand in Norway expected to increase to 134 TWh in 2020 and 143 TWh in 2030 (Statnett, 2015a, p. 55). Assuming linear growth, this indicates a 2025 demand figure of roughly $\frac{134+143}{2} = 138.5 \approx 139$ TWh. Wind energy is expected to increase by 4 TWh from 2015 to 2020, and by 6 TWh from 2015 to 2030 (Statnett, 2015a, p. 56). Assuming linear growth yields a 5 TWh increase in wind energy in Norway by 2025. Hydropower production is expected to increase by just over 6 TWh from 2015 to 2020, and by just over 10 TWh from 2015 to 2030 (Statnett, 2015a, p. 56). Assuming linear growth yields an 8 TWh increase in wind energy in Norway by 2025. Summing up, the main figures of interest are as shown in Table 15 below.

Table 15 – Key power system development towards 2025, based on Statnett.

	Unit	**Increase 2015 to 2025**
Yearly hydro production	TWh	8
Wind energy	TWh	5
Demand	TWh	9

The present and future data combined

Table 16 – Key figures on the Norwegian system, present and anno 2025. Values with a (*) are calculated values based on the two other columns.

	Unit	**Present**		**2025**	**Difference**
			Source		
Yearly hydro production	TWh	130	2.1	138*	8
Demand	TWh	130	2.1	139*	9
Wind energy	TWh	1.85	Regression[14]	6.85*	5
Hydropower capacity	GW	31.0	2.2.4	33.8	2.8*
Germany: Sun capacity	GW	-	-	54.0	-
UK: Offshore wind capacity	GW	-	-	25.7	-

[14] Differences in calculation method based on regression results have caused a mismatch between this number and the 1.89 TWh estimated in the Base case discussion in Section 5.3. The error is not considered to affect results notably. 1.85 TWh come from scaling based on hydropower production and production mix: $\frac{1.36}{95.29} \cdot 129.8 = 1.85$.

The two quantifiable scenarios are summed up in Table 16 above. This time the numbers are also matched with our best estimates for the present system. All calculated numbers are marked with a star.

5.5 Scenario A – Small storage

"Ambitions are at a moderate level both in Norway and EU; leads to a small volume of balancing over various time scales." (Sauterleute et al., 2015, p. 29)

5.5.1 Qualitative description

The first scenario, "small storage" is situated in the crossing between a *future* involving medium Norway-EU-integration and a *strategy* of moderate expansion by Norwegian decision makers. In total, the HydroBalance-scenario is qualitatively located along 10 different axes. This is detailed in Figure 13 below (left side). It shows a technical climate as follows: Variable renewable energy sources (VRES or Variable RES) have a medium share of the electricity generation, the European transmission grid undergoes a moderate expansion in the coming years, and carbon capture and storage (CCS) is deployed. In Norway, the story is much the same: The transmission grid also undergoes a moderate expansion, interest in new pumped storage power plants (PSPPs) and upgrading existing hydro storage power plants (HSPPs) is moderate, and variable renewables have moderate support. Market-wise, competition from new alternative technologies for power balancing is low, whereas EU regulatory framework and market integration is highly developed. In terms of policies, both Norway and the other European countries show moderate ambitions to connect Norway to Europe as a way of covering energy and balancing needs.

Uncertainties in Future 1	Medium
Technology	
Variable RES share of electricity generation	Medium
Expansion of European transmission grid	Moderate
Deployment of CCS	Yes
Market	
Competition from alternative flexible technologies	Low
EU regulatory framework and market integration	Fully integrated
Policy	
Ambitions of countries to connect to Norway	Moderate
Options in Strategy 2	**Moderate expansion**
Expansion of Norwegian transmission grid	Moderate
New PSPP and upgrade of existing HSPP	Moderate
Support of variable RES in Norway	Moderate
Ambitions of Norway to build interconnectors	Moderate

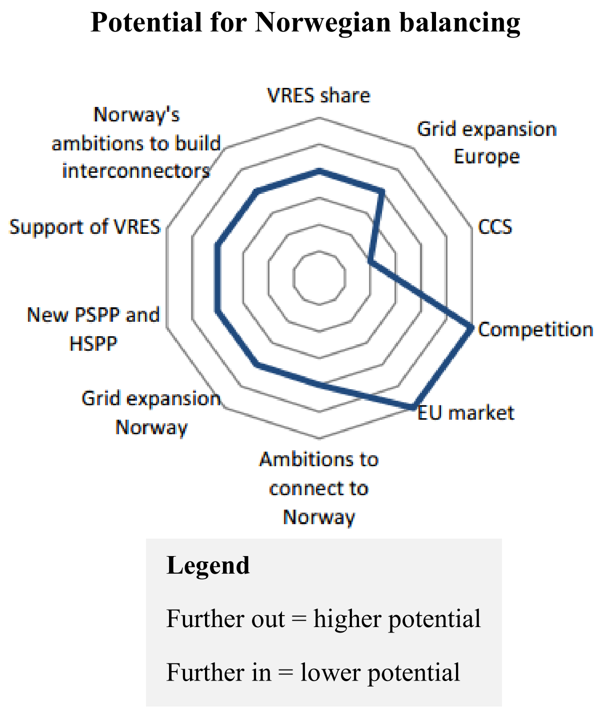

Figure 13 - Details of HydroBalance Scenario A - Small storage.[15]

The right part of Figure 13 shows how each of the factors from the left hand side affects the potential for Norwegian hydropower to deliver balancing to Europe. Further out towards the edge of the diagram represents a larger potential. In most aspects, Scenario A represents a medium potential for Norwegian balancing power. The fully integrated EU markets and low competition from alternative balancing technologies, however, pull upwards towards a higher potential. Deployment of carbon capturing (CCS), however, represents a loss of balancing potential.

5.5.2 Quantifying Scenario A

All these qualitative factors now need to come together in a solely quantitative simulation case. We seek to quantify how much hydro production, pumped storage, wind and solar capacity would fit this scenario, as well as the amount of interconnection between Norway and Germany and UK. The electricity demand will also be changed.

For the sake of simplicity, we will not add additional hydropower energy to our data set (but we will add production capacity to the existing plants). Keeping the hydropower energy

[15] Reprinted from "Scenarios for large-scale balancing and energy storage from Norwegian hydropower" by J. F. Sauterleute, Graabak, & Wolfgang (2014, pp. 10, 14). Reprinted with permission.

output constant means that we are changing our Base case scaling factor of $\frac{8.90}{130}$, as it is based on hydro production. From Table 16 on page 73, we see that the expected increase in yearly delivered hydro power energy is 8 TWh, meaning we should start scaling our system by a factor of $\frac{8.90}{138}$. This means, in practice, that our 8.9 TWh hydropower system constitutes a smaller part of the Norwegian system in 2025 than in 2014.

Production capacity and pumped storage

In Norway, the stipulated moderate upgrade in installed generation capacity is assumed to follow ENTSO-E's Best Estimate Scenario. From Table 16 on page 73 we find that this indicates a net installed hydropower capacity of 33.8 GW in the year 2025, an increase of 2.8 GW from the 2013 level presented in Section 2.2.4. Scaled to our system, this would indicate a capacity increase of $2.8 \cdot \frac{8.90}{138} = 0.18$ GW or roughly 180 MW. Out of this, let us assume that roughly half of the new installed hydropower production capacity is installed as reversible pump turbines. This assumption is *not* based on data from Statnett or ENTSO-E, but an estimate of what capacity would fit into our current system. Rounding up, we decide to increase production capacity by 100 MW with reversible pump turbines, and 80 MW of increased production capacity in normal power plants. The 80 MW is added to the Otra watercourse, at the Brokke power station producing water from the Bossvatn reservoir. Maximum production here is increased from 305.9 MW to 385.9 MW. All parameters are scaled accordingly, meaning that the efficiency is kept as is. Implementation data is shown in Table 36 in Appendix F.

A portion of the Otra waterway is shown in Figure 14 below: The Vatnedal and Bossvatn reservoirs, with Holen power station in between and Brokke power station below. In addition to the stipulated inflow to the Vatnedal reservoir, there is a considerable amount of inflow to the reservoirs located further up in the Otra waterway: Roughly a quarter of the Otra waterway's volume inflow falls above the Holen power station. Rough calculations indicate that this more or less equals the total reservoir capacity at Vatnedal. This also means that the Bossvatn reservoir receives roughly four times its reservoir capacity as inflow each yearl.

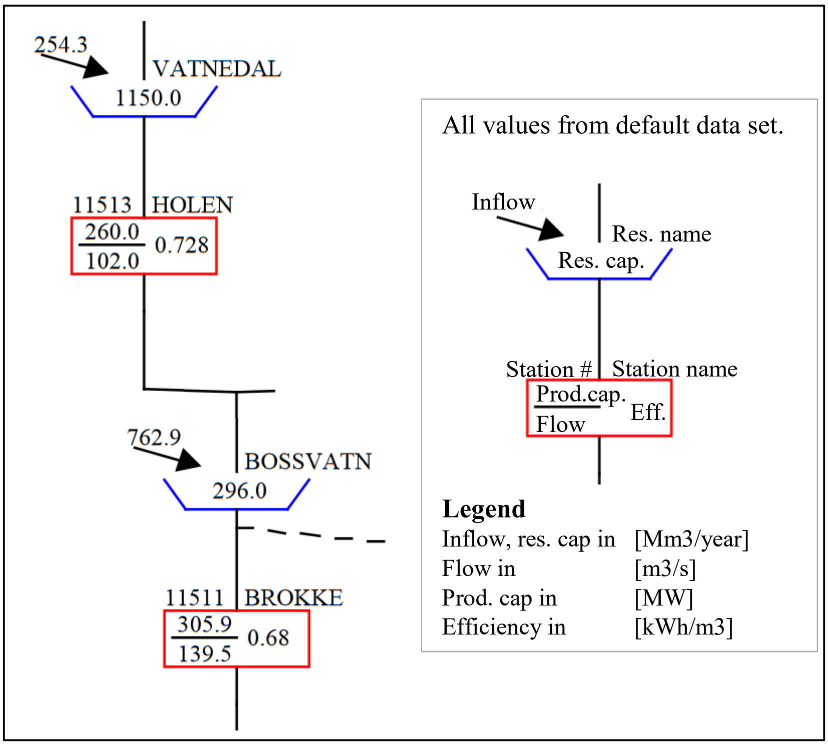

Figure 14 – Part of Otra waterway: Vatnedal and Bossvatn reservoirs.

As for the decision of where in the model to add the reversible pump capacity, there are two main aspects of interest: The size and the elevation difference of the reservoirs between which the pump is installed. Large reservoirs and a long drop means more energy is stored. In the current model there is one spot that is particularly suitable: The 300 meter drop from reservoir "Vatnedal" to "Bossvatn". This means we are still in the Otra watercourse. The upper reservoir is the largest, with 1150 Mm^3 of storage capacity. The lower reservoir holds up to 296 Mm^3 of water. The pump will be located at the Holen power station between the two reservoirs. In the Base case this plant has a maximum production capacity of 260 MW. Imagining that the old turbine is decommissioned and replaced with a 360 MW reversible one, we achieve what we set out to do. Production capacity is increased by 100 MW, and pumping capacity is increased by 360 MW. Note again that this number is chosen, not borrowed from one of the quantitative scenarios. On a Norwegian scale, 360 MW would translate to $0.36 \cdot \frac{138}{8.9} = 5.58$ GW of total reversible pump capacity. Or, assuming each of the installed plants were rated 4-500 MW, our estimate would mean that roughly 10-15 production plants had installed reversible turbines – this is considered highly plausible. In total then, Otra's production capacity is increased from 820 MW (Table 10, Section 5.1) to a new total of $820 + 80 + 100 = 1000$ MW. The overall hydropower-system production capacity is increased from 1965 to 2145 Mega-Watt, an increase of roughly nine percent.

Pumped storage hydropower plants typically have a total (round-trip) efficiency of about 80% (Gogstad, 2015, p. 4). Assuming that the pumping and the power production are roughly as efficient, each will be assumed to have a coefficient of efficiency of about 0.89. The Base case production capacity of this station is 260 MW with a water flow of 102 m^3/s. With a mean drop of 300 m between the reservoirs and an energy-coefficient of 0.7282 kWh/m^3, the average efficiency is calculated as follows:

$$\eta = \frac{0.7282\ [\frac{\mathrm{kWh}}{\mathrm{m}^3}]}{m{\cdot}g{\cdot}h} = \frac{0.7282\ [\frac{\mathrm{kWh}}{\mathrm{m}^3}]}{10^3 \cdot 9.81 \cdot 300\ [\frac{\mathrm{J}}{\mathrm{m}^3}]} = \frac{0.7282\ [\frac{\mathrm{kWh}}{\mathrm{m}^3}]}{9.81 \cdot 300 \cdot \frac{1}{3600}\ [\frac{\mathrm{kWh}}{\mathrm{m}^3}]} = \frac{0.7282}{0.8175}$$

$$= 89.1\%$$

This number is in the area that would, combined with our pump efficiency of 89 %, yield a total efficiency of 80 %, and so we would like to keep this level of efficiency (Note, however, that this efficiency is not constant, it varies for production output). Now, to increase the production capacity from 260 MW to 360 MW, water throughput and production are simply scaled up by a factor of $\frac{360}{260} = 1.38$. We will now take a look at the specifics of the new pump. A pump drawing 360 MW with an efficiency of 89 % will then exert about 320 MW of power on the water. We will assume that the pump has a constant efficiency for all throughput levels. For a given height difference one can then calculate the amount of water the pump is able to move. The mean height difference between the two chosen reservoirs is 300 m; the altitude difference between the two water surfaces, however, will vary with the reservoir levels of both reservoirs. Looking at the lowest and highest regulated water levels in the two reservoirs we can find the maximum and minimum elevation differences. In our case the lower reservoir can vary between 495 m and 551 m, while the upper reservoir is restricted between 700 and 840 meters. This means that the lowest height the water needs to be lifted is $700 - 551 = 149$ m, and the highest is $840 - 495 = 345$ m. Assuming that our pump exerts the same amount of power on the water regardless of the height difference (i.e. 320 MW), the flow of water through the pump will have to be significantly higher in the case of the lowest height difference. This is perhaps not completely realistic, as it means that the waterways will have to be dimensioned to the high water volumes of the lowest height difference. We will, nonetheless, accept this assumption here. Calculating the required flow of water for each of the two extremes is done as follows:

$$\dot{V}\left[\frac{\mathrm{m}^3}{\mathrm{s}}\right] = \dot{m} * 10^{-3}[\mathrm{kg/s}] = \frac{P}{g * \Delta h * 10^3}\left[\frac{\mathrm{m}^3}{\mathrm{s}}\right]$$

$$\dot{V}_{149m} = \dot{m} = \frac{320 * 10^6}{9.81 * 149 * 10^3} = 219\left[\frac{\mathrm{m}^3}{\mathrm{s}}\right]$$

$$\dot{V}_{345m} = \dot{m} = \frac{320 * 10^6}{9.81 * 345 * 10^3} = 94.6\left[\frac{\mathrm{m}^3}{\mathrm{s}}\right]$$

These values are implemented into the modelled data set. The implementation is shown in Appendix F.

Norwegian wind power

Looking at the development of the other renewables in Norway, and assuming moderate support as the scenario suggests, we choose to increase the amount of "Norwegian" wind power from 127 GWh to 442 GWh. ENTSO-E predicts very limited PV generation in Norway, so no solar power will be added (ENTSO-E, 2015b). The added wind power is simply scaled down from the 6.85 Terra-Watt-hours 2025-estimate from Table 16 (page 73) as follows: $6.85[\mathrm{TWh}] \cdot \frac{8.90}{138} = 442$ GWh. Analysing all 50 years of wind input used, the largest and smallest observed power contribution is roughly 540 GWh and 350 GWh, respectively. Since the same wind input series is used as in Base case, only scaled up, the largest variations still lie within roughly ± 20 percent of the average. This time, however, the difference between the largest and smallest contribution is up to almost 200 GWh – which is starting to become relevant for the systems yearly energy balance (compared to 8.9 TWh from hydro). Remember from 5.2.1 that wind energy is given as energy, not capacity, due to the way wind is implemented into the models: As uncontrollable production. As far as the models are concerned, new non-storable renewables can be handled as negative load series; series of hourly production numbers set fixed power output levels the same way the load series set fixed demand levels. The installed capacity required to produce a given amount of energy can only be estimated by assuming some average usage time. Using the average capacity factor in Norway today in a normal year, from Table 2, page 12, the calculation is done as follows (for Norway and for the modelled system, respectively):

$$P^{Norway}_{wind,estimate,SA} = \frac{W_{yearly}}{T_{Usage}[\mathrm{h}]} = \frac{1000[\frac{\mathrm{GWh}}{\mathrm{TWh}}] \cdot 6.85[\mathrm{TWh}]}{2692[\mathrm{h}]} = 2.55[\mathrm{GW}]$$

$$P^{model}_{wind,estimate,SA} = \frac{1000 \cdot 442[\mathrm{GWh}]}{2692[\mathrm{h}]} = 164[\mathrm{MW}]$$

This still composes less than eight percent of the 2145 MW of hydro power capacity installed. Nonetheless, it is a considerable increase from only 2.5 % in the Base case.

Demand

With the newly added wind energy of roughly 0.44 TWh, our system's energy balance is due to improve as the average delivered energy increases to $8.90 + 0.44 = 9.34$ TWh. We are, on the other hand, going to increase the demand as well. Following Statnett's 2025 scenario, where Norway's yearly power demand increases by 9 TWh to 139 TWh, our system should see a total load of roughly $139 \cdot \frac{8.90}{138} = 8.96$ TWh, up from 8.9 TWh in the Base case. This is achieved through adding 60 GWh per year to the firm power contract "Fastkraftprognose" in "Term" and "Hode", respectively Remember, however, that a small implementation error in the Base case, as discussed in Section 5.3, led to only 8.83 TWh being implemented. As a result, the Scenario A load is roughly $8.83 + 0.06 = 8.89$ TWh, not 8.96 TWh. Note also that the increase, even as Norway's demand is expected to increase by 9 TWh, is only 60 GWh; it is actually almost negligible. This is due to the new scaling factor: Hydro production is more or less expected to follow the same trend as demand. The implementation can be seen in Table 39, Appendix F. In sum, then, our system produces roughly 9.34 TWh of hydro and wind power each year, compared to a load of 8.89 TWh. This means that, even without thermal generation, our 2025-inspired "Small storage" system is at a power surplus, and should be able to sell/export power.

Interconnection to Germany and UK

Moving on to continental Europe, with Germany, as well as the British Isles, we start by taking a look at the interconnection to Norway. This subsection mainly focuses on the quantification and implementation of a transfer series; refer to section 5.2.2 for a more in-depth discussion of motivation and methodology.

In this scenario we will assume that after the two planned HVDC-links to Germany and the UK discussed in paragraph 2.2.3, no new subsea-cables are built during the next 10 years or so. This assumption is in part motivated by Statnett's scenario of expected future development for the period 2020 to 2030; It suggests a build stop in new cables during this period (Statnett, 2015a, p. 59). Since the "Small storage" scenario does, however, include efforts to develop market integration and to connect Norway and EU, it is assumed that the connectors are utilized close to their full potential. In other words, of the planned 1400 MW capacity connecting Norway to the UK and to Germany, all 1400 MW are modelled as available to the market. Scaling down this number, we decide to implement two interconnectors of $1400 \cdot \frac{8.9}{138} = 90$ MW each.

Starting off with solar power in Germany, we set out to model how the future that this scenario represents affects the Norwegian hydropower system. ENTSO-E's 2025 Best Estimate-scenario indicates that Germany as a whole will have an installed PV capacity of roughly 54.0 GW (ENTSO-E, 2015b). This number is also scaled down, to $54.0 \cdot \frac{8.9}{138} = 3.48$ GW, as the power will flow on the scaled down interconnector. Using the average production levels for German PV from Section 2.3.2, this indicates yearly energy supply levels for the full-size and model-size systems of roughly $54.0 \cdot 0.86 \left[\frac{\text{TWh}}{\text{GW}}\right] = 46$ TWh and $3.48 \cdot 0.86 \left[\frac{\text{TWh}}{\text{GW}}\right] = 3.0$ TWh, respectively. As discussed in Section 5.2.2, a transfer profile is created by combining a German PV production profile and a German load profile. The load profile is scaled to equal a yearly consumption of 0.64 TWh. Scaled up, this is $0.64 \cdot \frac{138}{8.9} = 9.9$ TWh. This is considerably less than the 3 TWh of PV generation, but when the sum series' peaks are cut down to 90 MWh/h, the net energy contribution is negligible (less than 0.1 GWh/year). In practice this means that we are connecting "Norway" to a part of "Germany" that is energy-balanced, but have limited short-term balancing capacity, as the HydroBalance-scenario suggests. For this series, the maximum transfer capacity is utilized 45 % of the time, on average. Motivated by the discussion in 5.2.2, where it was noted that interconnectors should generally see high usage, this level of utilization seems a little low. It is due to the way we have implemented the interconnector as energy neutral: The low scaling of the load series required to maintain zero energy contribution means that there is not that many hours where import needs exceed the transfer limit.

In ProdMarket, the transfer series is added to the "Hode" area; in EMPS it is added to "Term". The added renewable power production, although limited to 90 MWh/h, could have significant yearly impacts on our system. Crucially, even though the constructed combined load and generation series are energy balanced over 50 years, each year introduces a smaller or larger deviation from this balance. A 90 MW cable could theoretically transfer 90 MWh per hour, 2.2 GWh per day, 15 GWh per week and roughly 790 GWh or 0.79 TWh per year. Yearly variations from the expected energy outputs from German PV and British offshore wind could have impacts on the net flow of energy on the interconnectors. Analysing all 50 years of the combined German solar and load series, the largest power surplus and deficit is a mere 7.9 GWh and -15 GWh, respectively. This means that even in years of high or low solar production, the transmission capacity will have negligible impacts on the energy balance of our 8.9 TWh system.

UK offshore wind is handled in the same manner as that of German PV. For the case of installed offshore wind capacity in the UK, ENTSO-E's 2025 Best Estimate-scenario estimates 25.7 GW (ENTSO-E, 2015b), estimated to produce $25.7 \cdot 3.0 = 77$ TWh (using our rough estimate on average production levels from Section 2.3.1). This is $25.7 \cdot \frac{8.9}{138} = 1.66$ GW or $1.66 \cdot 3.0 = 5.0$ TWh when scaled down. This time, a 4.2 TWh UK load series is subtracted from the production series. Scaled up, this is $4.2 \cdot \frac{138}{8.9} = 65$ TWh. Once again, after cutting the resulting series down to the maximum capacity of the 90 MW interconnector, the net energy contribution in a mean year is zero. For this series, the maximum transfer capacity is utilized 90 % of the time in an average year – much higher usage than for the German series. This is due to the more equal amount of load and generation added together to create the transfer series (while maintaining energy balance) – fewer hours now lie within the transfer limits. The largest yearly power surplus and deficit is roughly 140 GWh and -160 GWh, respectively. The difference is around 300 GWh; this means that the UK offshore wind series could have some impact on our system's energy balance in extreme years, more so than the Norwegian wind power.

Scenario A – "Small storage" settings as implemented in the model are shown in Appendix F.

5.6 Scenario B – Big storage

"EU's and Norway's development are complementary; this leads to high demand and large volume of balancing from Norway over various time scales." (Sauterleute et al., 2015, p. 30)

5.6.1 Qualitative description

This really is "the big one" as far as the potential for balancing using hydropower storage goes. This scenario pictures near-perfect technical and economic conditions for pumped storage, and hence serves as a reference for the potential it holds. Consequently, it also reveals the optimization models' potentials in terms of handling profound changes in the energy sector. The only factor negatively impacting Norway's potential to provide hydro storage balancing to Europe is the fact that Norway, too, sees an increased development of variable renewable energy sources. This is reflected by the radar diagram on the right-hand side of

Figure 15 below, which is close to being a complete circle along the outermost line of the diagram.

Uncertainties in Future 3	Various flexibility
Technology	
Variable RES share of electricity generation	High
Expansion of European transmission grid	Strong
Deployment of CCS	No
Market	
Competition from alternative flexible technologies	Low
EU regulatory framework and market integration	Fully integrated
Policy	
Ambitions of countries to connect to Norway	Strong
Options in Strategy 1	**Active climate policy**
Expansion of Norwegian transmission grid	Strong
New PSPP and upgrade of existing HSPP	Strong
Support of variable RES in Norway	Strong
Ambitions of Norway to build interconnectors	Strong

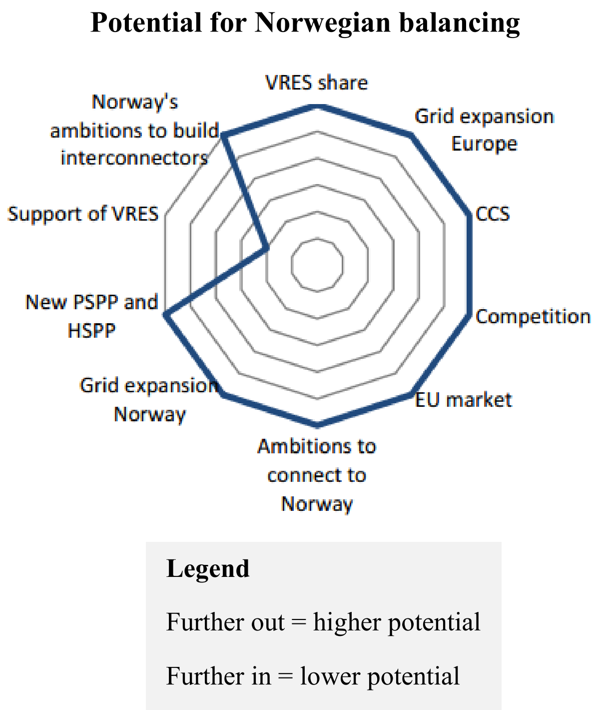

Figure 15 - Details of HydroBalance Scenario B - Big storage.[16]

5.6.2 Quantifying Scenario B

Compared to Scenario A, this scenario is more loosely connected to the quantified scenarios from Statnett and ENTSO-E. The scenario is mostly based on relative scaling of the sizes implemented in Scenario A. The scaling in itself is a result of qualified guesses. Although arguably less “accurate”, this approach nonetheless fits this scenario: The “Big storage” scenario was chosen for its potential, not its likelihood; review Section 5.4 to recapitulate the background for this. In this respect, Scenario B could have been taken even further than what is done in the following subsection; with more time available it would have been a matter of iterating between observing how the modelled system reacts and increasing scaling factors as compared to Scenario A. In this case, however, Scenario B is kept somewhat “sober”; Scenario A values are generally scaled up by a factor of 1.25 to 2.

Another scaling factor of interest is our system’s hydropower scaling factor as compared to the Norwegian system; it will be kept as is for this scenario: $\frac{8.9}{138} \approx 6.4$ %. This means that we

[16] Reprinted from "Scenarios for large-scale balancing and energy storage from Norwegian hydropower" by J. F. Sauterleute, Graabak, & Wolfgang (2014, pp. 11, 14). Reprinted with permission.

assume similar average production levels from the Norwegian hydropower system as in Scenario A, i.e. 138 TWh. It could be argued that the future scenario could warrant a slight increase in hydropower development, but it is assumed that future focus would be on capacity, not energy – as there are other renewable energy sources present that more than outweigh the assumed load increase.

Production capacity and pumped storage

Scenario B, "Big storage", suggests favourable conditions for pumped hydro-electric storage. Moreover, it suggests that these conditions are taken advantage of: Large amounts of hydropower production capacity as well as pumped hydro capacity is added to the system. Where Scenario A followed ENTSO-E, increasing installed production capacity by 180 MW, of which 100 came in the form of 360 MW reversible turbines, the "Big storage" scenario will introduce significantly more. The production capacity will be increased by 400 MW, of which 240 MW comes from reversible turbines with a total pump and production capacity of 500 MW. Hence, production from conventional non-reversible plants are increased by the remaining 160 MW. For Scenario B then, the system's total production capacity is increased from 1965 MW in the Base case (Table 10, section 5.3) to a new total of $1965 + 400 = 2365$ MW, a considerable increase of about 20%. On a Norwegian scale, this production capacity equals $2.365 \cdot \frac{138}{8.9} = 36.7$ GW, up from 31.0 GW in the Base case. The more than doubled increase in production capacity is motivated by the assumed increase in financial payback from providing balancing power. As in Scenario A, 80 MW of the increased production capacity is implemented at the Brokke power station in the Otra watercourse. Like previously, its production capacity is increased from 305.9 MW to 385.9 MW. The remaining 80 MW is implemented at "Nore" power station, the largest power station in "Numedal". Production capacity here is increased from 200.0 MW to 280.0 MW. Implementation data for both plants are shown in Appendix G. Also similar to Scenario A, the reversible pump will be installed in the Otra watercourse, at the Holen power-station. This time, the pump and production capacity will be 500 MW (with a pump efficiency of 89%, the pump now effectively exerts 445 MW of power on the water). All sizes are scaled accordingly; implementation is also shown in Appendix G.

Remember from Section 2.2.5, where an estimated Norwegian potential for PHES of 20 GW was quoted. In comparison, 500 MW of pumped storage represents $0.500 \cdot \frac{138}{8.9} = 7.75$ GW on a Norwegian scale. Repeating the back-of-the-envelope calculation from Scenario A, this requires roughly 15 to 20 reversible power stations with capacities of around 4-500 MW. Given the right economic conditions, this is still considered a cautious estimate.

Norwegian wind power

Scenario B is implemented with 900 GWh of Norwegian wind power. Scaled up from our modelled system size to full Norwegian size, this equals $0.900 \cdot \frac{138}{9.8} = 14.0$ TWh of wind energy. This is a considerable amount, arguably a tad optimistic for a future "only" ten years ahead. It is nonetheless considered plausible, as it would take no more than 10-15 "Fosen Vind"-size projects to realize it. The number does, however, incorporate an expectation that large-scale offshore wind may be realized in Norway given the right financial and political conditions – in which case Norway's wind power potential is further multiplied.

Analysing all 50 years of wind input used, the largest and smallest observed power contribution is roughly 1.1 TWh and 0.7 TWh, respectively. The wind input series is the same as in the previous cases, only scaled up, so once again the largest variations still lie within roughly ± 20 percent of the average. This time, however, the difference between the largest and smallest contribution is up to 400 GWh, more than doubled from Scenario A, constituting around 4.5 % of the system's total hydropower production.

Once again, the approximate installed wind power capacity required to produce such energy amounts is calculated based on usage times from Table 2, Section 2.3.1:

$$P_{wind,estimate,SB}^{Norway} = \frac{W_{yearly}}{T_{Usage}[\mathrm{h}]} = \frac{1000[\frac{\mathrm{GWh}}{\mathrm{TWh}}] \cdot 14.0[\mathrm{TWh}]}{2692[\mathrm{h}]} = 5.20[\mathrm{GW}]$$

$$P_{wind,estimate,SB}^{model} = \frac{1000 \cdot 442[\mathrm{GWh}]}{2692[\mathrm{h}]} = 334[\mathrm{MW}]$$

This constitutes around 14 percent of the 2365 MW of hydro power capacity installed in our system. This is a considerable increase from only 2.5 % in the Base case; wind power is becoming a notable source of energy and capacity in Norway.

Demand

It is assumed that Norway's energy balance is improved in Scenario B; the extra wind energy is assumed *not* coupled with large increases in domestic load. This fits into the scenario: Increased interconnection to the continent is presumably at least in part motivated by Norway's energy surplus and higher prices on the continent. The load level will be kept as in Scenario A, i.e. 60 GWh higher than in the Base Case. The systems approximate energy balance improves, as the total combined hydropower and wind energy increases to approximately $8.9 + 0.9 = 9.8$ TWh, compared to a load of 8.96 TWh. The implementation can be seen in Appendix G.

Interconnection to Germany and UK

This subsection mainly focuses on the quantification and implementation of a transfer series; refer to section 5.2.2 for a more in-depth discussion of motivation and methodology.

During implementation of Scenario A it was argued that, based on Statnett's expectations, there would be no further increase in continental transfer capacity apart from the already planned 1400 MW interconnectors to the UK and Germany. Nonetheless, the implementation of Scenario B will increase this capacity by 50 percent per cable. In practice, the 50 percent increase in capacity for each interconnection might as well be viewed as the addition of a third connector, also of 1400 MW, to a third country with equal amounts of sun and wind energy. In any way, each 1400 MW interconnector is extended to 2100 MW. Or, in scaled down numbers, the implemented capacity is increased from 90 to 135 MW.

In Scenario A, the ENTSO-E's 2025 Best Estimate-scenario was used as a basis to increase PV capacity to 54 GW in Germany, which was estimated to equal roughly 46 TWh. For Scenario B, a somewhat larger increase in renewable production in Germany will be assumed – in line with HydroBalance's "Big storage" scenario. The 46 TWh will be increased by 25 percent to $46 \cdot 1.25 = 58$ TWh, equalling roughly $\frac{58}{0.86} = 67$ GW of installed solar-power capacity. Scaled down, these sizes become $58 \cdot \frac{8.9}{138} = 3.7$ TWh and $67 \cdot \frac{8.9}{138} = 4.3$ GW. As before, the PV production is matched with a load series, the resulting series is cut down to the transfer limit (of 135 MW) and balanced in terms of energy contribution. The load series is scaled to a size of a little over 14 TWh or $14 \cdot \frac{8.9}{138} = 0.90$ TWh on Norwegian and model scale, respectively. This results in maximum transmission capacity being used in 42.6 % of the time. Analysing all 50 years of the combined German solar and load series, the largest power deficit and surplus is 13 GWh and -24 GWh, respectively. As in Scenario A, this is negligible in the large picture.

As for the UK offshore wind, it too will be increased by 25 percent, to a new level of $77 \cdot 1.25 = 96$ TWh. This now equals roughly $\frac{96\ [\text{TWh}]}{3.0\ [\text{TWh}/_{\text{GW}}]} = 32$ GW of installed wind capacity, using the average production level discussed in Section 2.3.1. Scaled down to system size, the production series used totals $96 \cdot \frac{8.9}{138} = 6.2$ TWh and represents roughly $32 \cdot \frac{8.9}{138} = 2.1$ GW of installed offshore wind power. This time a load series of circa 81 TWh, or $81 \cdot \frac{8.9}{138} = 5.2$ TWh in system scale, is subtracted. The difference between the two is subsequently cut down to 135 MW. The transfer capacity is fully utilized 88 % of the time. The net transfer series yields no energy contribution to our system in an average year, but 210 GWh and - 240 GWh in a power deficit and surplus year, respectively. This is becoming notable: The difference is around 450 GWh, a little more than the variability from the Norwegian wind power. Combined, the Norwegian wind power and UK interconnector could contribute yearly differences of up to $400 + 450 = 950$ GWh. Due to differing placement and the geographical spread, however, the correlation between Norwegian wind power and UK offshore wind is likely somewhat limited – so it is unlikely (albeit not impossible) that the two have all-time-low or -high production years simultaneously.

Scenario B – “Big storage” settings as implemented in the model are shown in Appendix G.

5.7 Case summary

Table 17 on the following page summarizes most of the information presented for our three simulation cases, both on the scale of our model, and on the scale of the entire Norwegian power system.

Table 17 – Simulation cases, summary.

Scale	Case	Norway					Germany			UK		
		Hydro prod.	Load	PHES	Hydro prod. cap.	Wind gen.	Solar gen.	Load	Transfer cap.	Offshore wind gen.	Load	Transfer cap.
	Unit	TWh/year	TWh/year	GW	GW	TWh/year	TWh/year	TWh/year	MW	TWh/year	TWh/year	MW
Norway	BC	130	130	0	31.0	1.85	-	-	-	-	-	-
	SA	138	139	5.58	33.8	6.85	46	9.9	1400	77	65	1400
	SB	138	139	7.75	36.7	14.0	58	14	2100	96	81	2100
	Unit	TWh/year	TWh/year	MW	MW	GWh/year	TWh/year	TWh/year		TWh/year	TWh/year	
Model	BC[17]	9.8	8.83	0	1965	127	-	-	-	-	-	-
	SA[18]	9.8	8.89	360	2145	442	3.0	0.64	90	5.0	4.2	90
	SB[19]	9.8	8.89	500	2365	900	3.7	0.9	135	6.2	5.2	135

[17] Base case is scaled to a factor of $\frac{8.9}{130}$ according to approximate system hydro production from modelled system and Norway's system anno 2025.

[18] Scenario A is scaled to a factor of $\frac{8.9}{138}$ according to system size.

[19] Scenario B is scaled to a factor of $\frac{8.9}{138}$ according to system size.

Chapter 6 Results and analysis

Chapter 6 will present simulation results for each of the three cases studied. We will look at power prices, magazine levels and handling, amount of spillage and bypass, need for rationing, and economic results. After that follows a subsection focusing the analysis on two key aspects of interest. But first, results regarding computation time and convergence are presented in section 6.1 below.

Results are extracted somewhat differently from each of the two models used. To maintain comparability, EOPS's result generator "ET.exe" has been used for most of the totalled results for both EMPS and ProdMarket. The "ET" module is normally used for single-area systems, and so it has to be used separately for each of EMPS's four areas. For ProdMarket, although the waterways are calculated separately, the whole system is implemented and calculated as one area, so the results are given as system totals as default. In order to produce comparable results, the EMPS area results have therefore been added together manually to represent total system results. Note that the overall results are given as total values over the simulation period, which is 156 weeks (i.e. three years), and not as yearly figures. Note also that most of the results are mean values over the 50 simulated inflow scenarios.

Support for wind and solar power in ProdMarket has only recently been added. As a result, it is not yet included in the executables that output results from the model. However, since wind and solar production is given from the input series alone, the two models' handling is known to be identical. Hence, the wind and solar results shown for ProdMarket are either calculated directly form the input series, or are simply copied from the EMPS results.

6.1 Run time, convergence

This section documents the results of the decisions made on run time and convergence from Section 4.3. Although run time and convergence results are arguably not as intuitive and interesting as discussions on economic surplus, they are crucially important for the usability of software models such as ProdMarket. In essence, the challenge lies in improving convergence while decreasing run time.

6.1.1 Run times

The ProdMarket-version used in this thesis did not support automatic logging of total run times, so run times were calculated based on the run time of the internal modules: the local ProdRisk optimization and the market simulator.[20] Below is a table showing estimated total calculation times.

Table 18 - ProdMarket run time for each simulation case.

Scenario	ProdRisk run time (based on final PM iteration) [h]			Market simulator run time (avg.) [h]	Estimated total run time	
	Numedal	TEV	Otra		[h]	[days]
BaseCase	23.08	24.23	23.07	0.422	247	10.3
SA	22.98	23.89	23.03	0.400	243	10.1
SB	22.72	23.80	22.48	0.401	242	10.1

The values in Table 18 are calculated as follows: $(\text{longest ProdRisk run time} + \text{market simulator run time}) \cdot 10 \text{ iterations}$. The table shows calculation times in the range of 10 days, as suggested in Section 4.3. Moreover, it shows that calculation times are relatively stable across the simulation cases; the added complexity of wind, solar and pumped storage in Scenario A and B have not increased calculation times. On the contrary, calculation times have decreased slightly. This is thought to come from the fact that the “Hot start” mode is used: It is plausible that calculations runs are ever-so-slightly faster when convergence is better. And as we shall see below, it is better for the later cases.

6.1.2 Convergence

The final values of the two convergence parameters used for ProdMarket’s outer iteration loop are shown in Table 19 below. The parameters describe the single largest absolute value deviation and the overall standard deviation from one iteration to the next. All three simulation runs reached the specified maximum iteration count limit of ten, as the convergence thresholds were not reached.

[20] Updated versions automatically record total run time (Henden, personal communication, 30.06.2016).

Table 19 - Convergence parameters, all scenarios

Scenario	Largest deviation between price periods [øre]	Standard deviation between price series [øre]
BaseCase	390	7.05
SA	243	4.57
SB	149	2.59
Threshold	10	4.0

Generally, the largest single deviations between price periods of the last two iterations are observed to be way above the threshold limit. This indicates that there are some extreme values where convergence cannot be easily achieved. This is likely in periods of water shortage, where one iteration suddenly reaches rationing prices (i.e. 450 øre/kWh). The standard deviation between the price series, however, is not as far from its threshold value, indicating that most values are not as far off as the extremes. For both convergence parameters, there is a clear trend towards improved convergence from one case to the next.

Another way of looking at convergence, is through visualizing the stability of the solution provided. Figure 16 plots power prices for each of the ten iterations of each simulation case. Although the standard deviation numbers in the above table is a mathematically more robust measure, the stability of the mean power price is perhaps more intuitive.

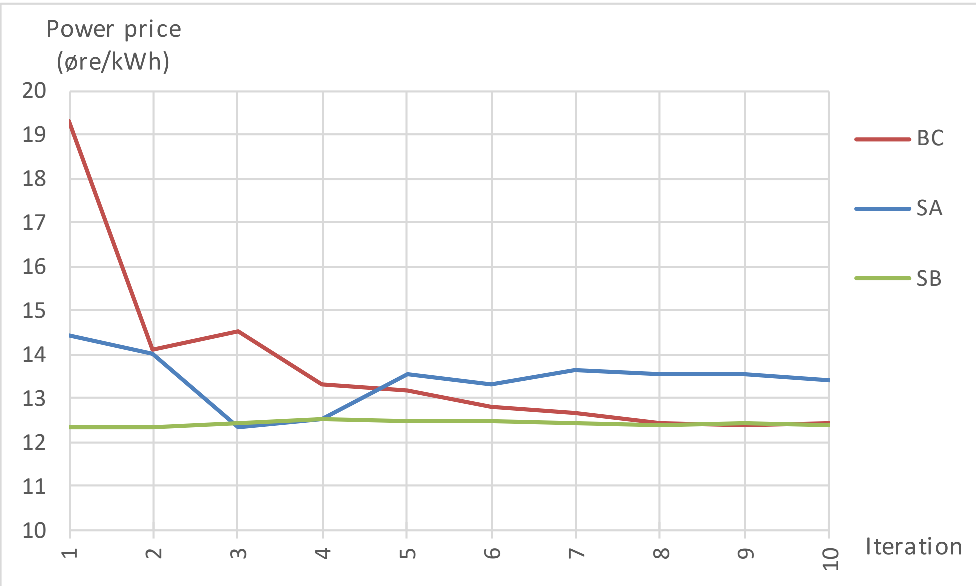

Figure 16 – Average power price per iteration, all case simulations. ProdMarket.

We observe from Figure 16 that, in terms of power price stability, 10 iterations seem to be sufficient for all three cases. For the Base case, it seems no less than ten should have been used; the future scenario cases, particularly Scenario B, could have seemingly made do with a little less (Although it is likely that the convergence parameters would have been affected negatively).

From section 4.3 we remember that ProdMarket is run using so-called “hot start”, meaning that each scenario simulation uses the previous simulation as a starting point for its calculations. This is likely the main factor in improving the convergence from the Base case to Scenario A, then B. Presumably, running 10 hot start iterations on three largely identical systems is not that different from running 30 iterations on a single system. The other plausible contributor to improved convergence is that as the system’s energy balance improves, and the risk of rationing decreases, price variations across the year and between scenarios are generally smaller. On the other hand, increased short-term price fluctuations due to variable renewable energy sources could have the adverse effect.

6.2 Base Case

The Base case results presented in this sub-section will provide a basis for comparison and discussion with regards to the future scenario cases. The results from EMPS and ProdMarket will also be discussed and compared to each other.

6.2.1 Overall results

Table 20, below, summarizes some of the most important simulation results for the present-time simulation case.

Table 20 - Results for Base case for EMPS and ProdMarket. Mean values. Numbers are total over 156 weeks.

		EMPS					ProdMarket
	Unit	Numedal	TEV	Otra	Term	**Total**	
Inflow	GWh	9316.8	7343.4	10935.6		27595.8	28096.9
Spillage and bypass	GWh	582.9	705.6	1048.0		2336.5	1652.5
Pumping, use	GWh			122.2		122.2	118.2
Pumping, gain	GWh			322.0		322.0	311.5
Pumping, net	GWh			199.8		199.8	193.3
Start magazine, sum	GWh	1070.8	1125.0	2003.9		4199.7	4199.7
End magazine, sum	GWh	827.1	1008.7	2146.8		3982.6	4632.7
Contracted power demand	GWh	8985.0	6547.5	9900.0	1050.0	26482.5	26482.6
Delivered hydropower	GWh	8977.5	6754.0	9944.5		25676.0	26204.7
Contracted power not deliv.	GWh	0.8	0.4	1.1	0.1	2.4	11.6
Interruptible load bought	GWh	172.6	0.0	259.2	1191.0	1622.8	1319.9
Interruptible load sold	GWh	792.8	29.5	347.8	29.5	1199.6	1057.0
Wind power, Norway	GWh				381.0	381.0	381.0
Contracted power not deliv.	MNOK	-0.5	-0.3	-0.7	0.0	-1.5	-15.1
Net interruptible load	MNOK	-1.6	7.3	-2.1	-176.5	-172.9	-133.0
Net income	MNOK	28.5	-39.3	150.5	-265.0	-125.3	-148.2
Magazine level changes	MNOK	-32.3	-17.9	5.6		-44.6	35.2
Net income, magazine adj.	MNOK	-3.9	-57.3	156.1	-265.0	-170.1	-113.0

Let us start from the top. The first row, "Inflow", shows how much water has entered the magazines during the simulation period. It should be similar between the models as the inflow scenarios from the data set is equal. Indeed, EMPS and ProdMarket inflow numbers are in a similar range. Nonetheless, "Inflow" varies somewhat between cases and models, as the inflow figure given here is also influenced by how the system is operated; e.g. net energy contribution from pumping is subtracted from the inflow (SINTEF, n.d.-b, p. 249). Furthermore, note that "Inflow" here is given as an energy equivalent, in GWh, which varies with magazine levels due to head variations. The second row from the top, “Spillage and bypass”, is the sum of water inflow that the models have not been able to store or produce. It represents a loss in that the water could have potentially been utilized for power production. The fact that ProdMarket has less spillage than EMPS, means that it has more water available to cover its load obligations and hence less change of rationing. Rationing is included in the row named “contracted power not delivered”, which includes both curtailment and repurchasing of load. This row represents a direct cost, as shown in the economic results further down the table. Looking at the numbers, we see that EMPS manages to operate the system with less need for rationing; this reduces its costs compared ProdMarket. Related to rationing is the next two rows regarding buying and selling of “Interruptible load”. The two rows represent all the other price dependant power types, such as import and export to, substitutable load, interruptible industrial loads, thermal power and spot-market transactions (as discussed in section 5.2). EMPS both buys and sells more of this interruptible power than ProdMarket. The economic effect of this can be seen a little further down, under “Net interruptible load”, which shows the net income or cost of buying and selling such power. EMPS’s operational strategy involves spending roughly 40 MNOK more than ProdMarket does.

Moving on to sum magazine levels, two table rows represent start and end magazines, respectively. The start magazine level is identical between cases and between the models, as it is set directly by the run settings. The end magazine, however, varies between models and between each inflow scenario. EMPS has a somewhat lower end magazine compared to the start of the simulations. The row named “Delivered hydropower” shows how much power is produced in the hydropower system by each model. It shows that, even though ProdMarket has saved more water for later by increasing the sum magazine level, it has been able to deliver more power than the EMPS model. This is possible through the combination of higher inflow figures and considerably lower spillage and bypass. The only other source of energy in the modelled system that does not induce costs is wind. The implemented wind power’s energy contribution of $127 \cdot 3 = 381$ GWh is seen in results.

The three rows regarding pumping is show how much energy drawn by the pump, how much energy the pumped water represents when produced, and how much net energy this represents. The Base case only includes one small “non-reversible” pump, in the Otra waterway. It is used for pumping water from a reservoir with no production plant to a reservoir where the water can be utilized more efficiently. For this traditional way of pumping, the EMPS model and ProdMarket are closely aligned in terms of pump usage.

As for the load side of things, further down the table the "Contracted power demand" is exactly the same for both models; it is simply three times the yearly sum of contractual obligations ($8.83 \cdot 3 = 26.5$ TWh).

Economic results

Economically, EMPS's decrease in stored water is reflected by a negative value under "Magazine level changes". For ProdMarket, the magazine level is increased significantly during the course of the simulation. Conversely, this leads to a positive net change in valuation of stored water. The value of the magazine level changes is added to the operational income, the "Net income" row, to calculate the net *adjusted* income at the bottom row. Therefore, even though ProdMarket has lower operational "Net income", the "Net income, magazine adj." figure is higher (i.e. less negative). This final row is perhaps the single most important result in terms of comparing how the models perform. And comparing the two models, ProdMarket shows the better results. ProdMarket's cost level of 113 million NOK considerably better than EMPS' total cost of just over 170 MNOK. To put the results in perspective, we take a look at previous results on other versions of the same data set.

Henden's (2015b, p. 23) results based on calculations on a similar data set showed that ProdMarket had $-1067.1 + 1082.8 = 15.7$ MNOK better net income results than EMPS. Henden (2015b, p. 23) also suggests that the EMPS model should be able to provide notably better results than EOPS, as EMPS showed system costs $-1082.8 + 1118.3 = 35.5$ MNOK lower than EOPS. Kyllingstad (2015, p. 41) showed 38.5 MNOK better net income results for ProdMarket than for EOPS in the base case simulation. Seeing Kyllingstad's results in light of Henden's, the expected difference between ProdMarket and EMPS would shrink to next to nothing. How comparable are these results to this thesis? A couple of important changes to the data set and run settings speaks in favour of increased differences between the two models. First and foremost, both Henden (2015b, p. 11) and Kyllingstad (2015, p. 9) used four price periods, as opposed to 16 in this thesis. It is likely that the move from 4 to 16 price periods will have skewed the relation between EOPS/EMPS and ProdMarket in ProdMarket's favour – ProdMarket and ProdRisk are known to have superior short-term water handling as each magazine is considered separately in the optimization (Henden, personal communication, 27.05.2016). The same goes for the increased short term fluctuations in the power balance caused by the wind power included in our Base case data set. In Kyllingstad (2015, p. 41), ProdMarket's results improved relative to EOPS when short-term price fluctuations were increased by adding run-of-river hydropower (i.e. hydropower without significant reservoir capacity). Whether or not the effects of the run-of-river production is transferrable to wind power is, in part, the motivation behind the future scenarios studied in this thesis.

Our observed results show that ProdMarket's economic results are as much as $-170.1 + 113.0 = 57.1$ MNOK higher than EMPS results. Compared to Kyllingstad (2015) and Henden (2015b), this is more than expected. ProdMarket's somewhat high end reservoir is thought to be affected by a heightened end water valuation. As explained in section 4.3.3, there are a couple of reasons why the end valuation of water in ProdMarket could in our case be slightly optimistic. The hypothesis that the elevated end valuation could have boosted ProdMarket's results have been extensively researched. However, as will be discussed in Section 6.5.5, the external result calculation in the ET-module does not use ProdMarket's internal valuation to evaluate end magazine value. In effect, end valuation is considered likely to *reduce* ProdMarket's results, not *increase*.

Overall, ProdMarket seems to have done a good job at simulating this Base case. Now we will study some graphs to examine how magazine levels and power prices fluctuate over the simulation period.

6.2.2 Magazine handling

Section 4.3.3 discussed how the start and end point of the magazine curves are heavily affected by the boundary conditions of the simulation period. It was assumed, however, that "the actions taken to account for upcoming seasonal fluctuations simply overshadow most aspects regarding other seasons than the very next one". As specified by the run settings in Appendix A and B, both models have an identical start point of 70 percent magazine filling for all magazines, while end valuation is given by each models respective calculations.

Figure 17 below shows the sum reservoir levels for the entire simulation period. The plotted values are system totals, i.e. sums of all three simulated waterways, and averaged across the 50 inflow-scenarios. It seems that the start conditions affect the EMPS more than it does ProdMarket. ProdMarket manages to drop quite quickly down to a reservoir level that is kept similar from the first to the second year. The fall, i.e. the filling season, of the third year, however, the reservoir level reaches much higher levels – it seems obvious that simulation end conditions affect the results.

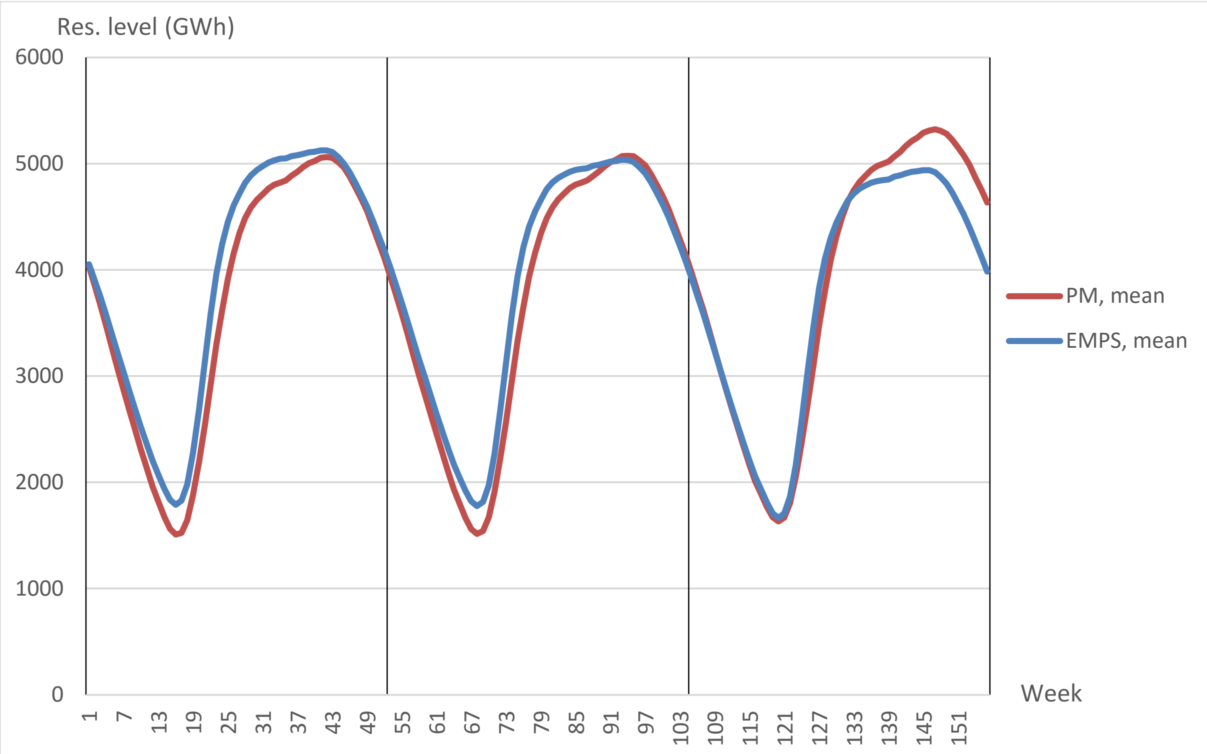

Figure 17 – Base Case sum reservoir level, mean. EMPS and ProdRisk. [21]

In addition to the start and end conditions, calibration settings can cause yearly differences in the EMPS model. Since it affects decisions taken throughout the simulated timespan, all three years are affected; and since the second and third years are mostly unaffected by the start condition, they can be tuned and shaped by altering calibration settings. Moreover, since the EMPS updates its end value estimates for each iteration, the calibration is also what affects the end valuation at the end of the simulation. In this case, Figure 17 shows a notable decrease in EMPS reservoir levels from one year to the next. This could indicate that the start condition has higher magazine filling than the EMPS model would choose on its own, and that the calibration settings motivate running the reservoirs lower.

Of course, a mean value plot as the one in Figure 17 above, only shows parts of the story. Figure 18 (below) and Figure 19 (below) show percentile plots of the same data. In both figures, the orange curve can be recognized as the mean value from Figure 17. This time, five percentiles are plotted alongside the mean: The 0, 25, 50, 75 and 100 percentiles. Together they represent the spread of the 50 inflow scenarios. It is important to note that percentile

[21] EMPS sum reservoir level is calculated as the sum of the sum reservoirs in each of the three waterways.

plots *do not* represent specific scenarios: Each plot line is made up of sections from many different scenario's magazine level curves. This is also evident by observing that the percentile plots never cross each other (the mean does, but it is not a percentile).

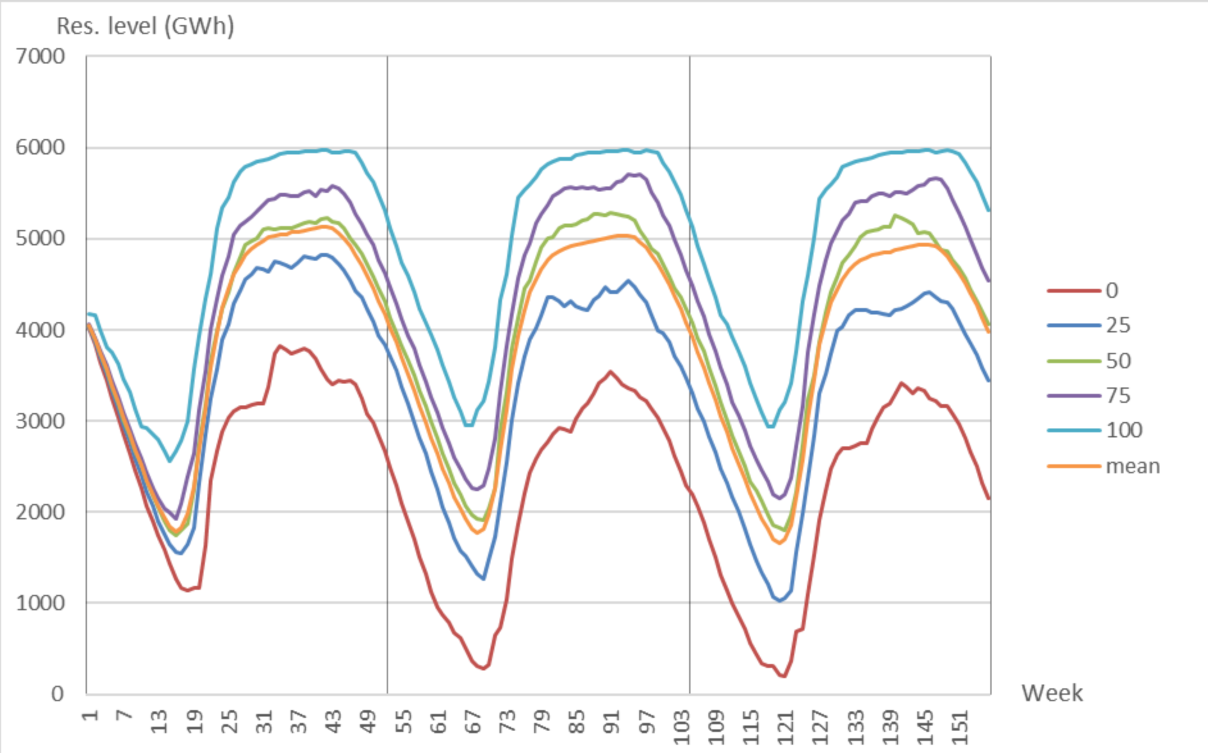

Figure 18 - Sum reservoir level, Base Case, EMPS. Percentiles. [22]

The above figure shows EMPS's percentile plot. It shows that the main bulk of scenarios, from the 25-percentile upwards, lie within a reasonably small spectre along the higher reservoir levels – this indicates a cautious magazine handling that is well prepared to handle dry years. And the dry years do come: The lowest quarter of the scenarios span a wide band all the way down to the very lowest values recorded at the 0-percentile. The model is nonetheless able to handle even the most extreme inflow years without emptying its reservoirs completely. We remember from Table 20, page 93, that there was, however, a limited amount of contracted load that was not fulfilled – why is that necessary if the reservoirs were never emptied? The answer is likely that, even though not all reservoirs were emptied, the remaining magazines did not have enough combined production capacity to cover all peak winter loads.

ProdMarket's percentile plot largely follows the same overall strategy; Figure 19 below shows this. But if we, once more, take a look at the lowest line, the 0-percentile, the gap from

[22] EMPS sum reservoir level is calculated as the sum of the sum reservoirs in each of the three waterways.

it to the 25-percentile line is even larger than for EMPS. It is unclear why, while the main bulk of scenarios follow trajectories similar to that of EMPS, ProdMarket's "outliers" are somewhat more extreme than those of EMPS.

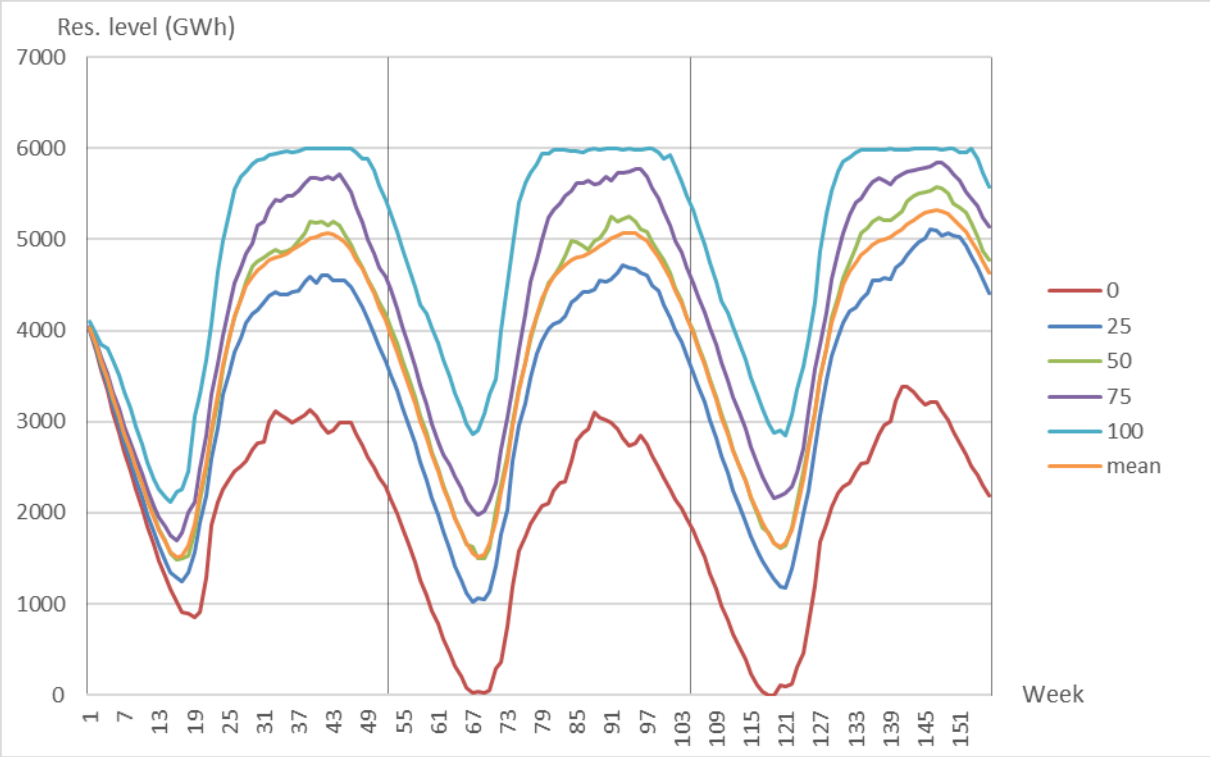

Figure 19 - Sum reservoir level, Base Case, ProdMarket. Percentiles.

As a comparison, the same 50 inflow scenarios used to create the above percentile plot is also plotted individually below; this format too can provide some insights.

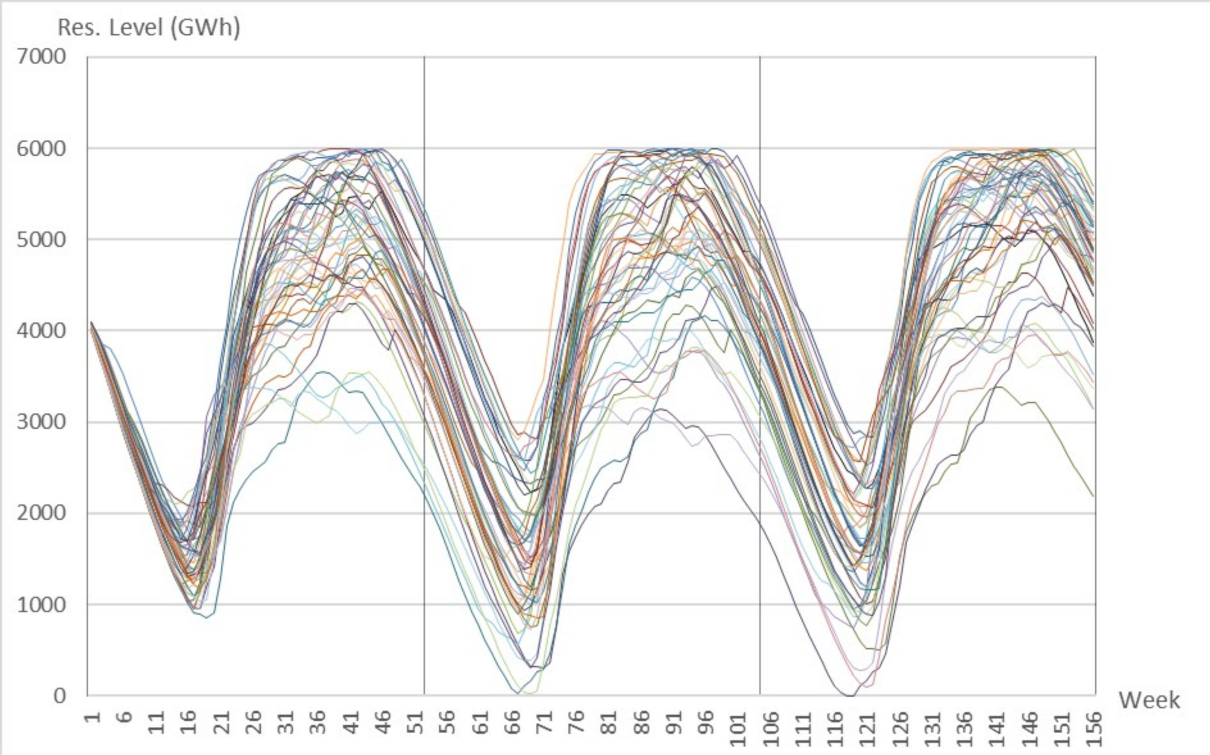

Figure 20 – Sum reservoir levels, Base case, ProdMarket. All inflow scenarios.

As we learned from the percentile plot, a very limited amount of series stands out in terms of having the lowest magazine levels. Looking more closely, it can be observed that the inflow series of the three driest summers and winters follow a similar pattern. As it turns out, all three series include the inflow year of 1940 – this year's inflow were apparently very scarce. Having three series include the same inflow year is possible as each series runs over three years: The series include 1940 as their first, middle and last year, respectively.

To conclude on overall water handling, ProdMarket and EMPS both provide reasonable solutions; neither revert to large-scale rationing, even in very dry years, while both manage to utilize the available magazine capacity reasonably well. Some unexpected results are seen towards the end of the simulation period, where ProdMarket increases magazine levels considerably compared to the first and second simulated year. It seems that the end value boundary condition in ProdMarket's optimization algorithm is unreasonably high; this subject will be discussed in greater detail later on. ProdMarket's superior handling of individual magazines, however, allows it to run the system with less spillage and bypass flows – this is one of the factors granting ProdMarket superior economic results. Now we will take a look at some power price plots.

6.2.3 Power price

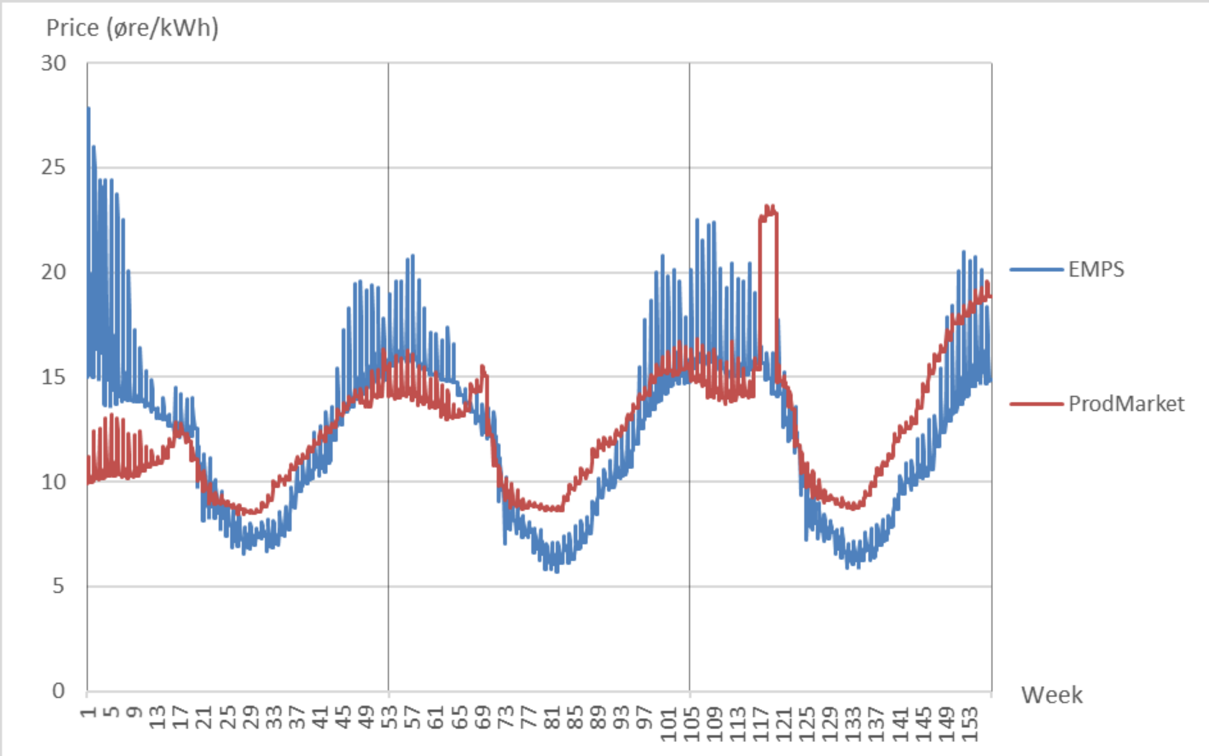

Figure 21 - Power price Base Case, mean. EMPS and ProdMarket. [23]

The above figure plots PM's and EMPS's average power prices over the simulation period. Generally, both models show increased prices during the so-called discharge season, which, as we remember from section 4.1, lasts from about week 40 to week 18 each winter. For year two and three, the end of the discharge season and start of the filling season is weeks 70 and 122, respectively. Quite steep price drops can be seen around this time for each simulated year. The varying yearly prices reflect the risk of rationing or spillage. During summer, there is a risk of full reservoirs leading to spillage, which implies zero water value and hence low prices. During winter, there is a risk that a dry inflow scenario will send the system towards rationing, where water values equal rationing costs. More often than not, however, as was seen in the magazine plots, the increased power prices mean that load is reduced or that hydro power is substituted by thermal power so that enough water can be saved to avoid massive load curtailment. This is also where power prices can reflect how good the economic results are: Lower average prices means that the model has had to buy less thermal power and curtailment. In this case, the numbers show that ProdMarket's average price is 12.4 øre/kWh,

[23] EMPS power price is taken from the "Numedal" area after verifying that differences between areas were negligible. Also note that although the x-axis reads "weeks", and reaches 156, there price is plotted for 156*16=2496 price periods.

as opposed to EMPS' 11.9. How does this fit in with PM's higher economic results, then? It actually fits in quite nicely, if the economic results are studied a bit more closely: We remember from Table 20 that ProdMarket shows higher net adjusted income, but recall also that ProdMarket had lower net income before magazine level adjustments were made. This means that ProdMarket has operated the system at a higher average cost during the simulation period in order to save more water for later. The decisive period is, of course, the last part of the third year, where ProdMarket raises prices significantly above EMPS to be able to save that excessive amount of water that the magazine curves identified.

To compare the two models' plots, there are some remarks to be made. First of all, even though in Figure 21 both models follow similar overall trajectories, the seasonal variations are larger for EMPS than for ProdMarket. What is preferable is debatable. Moreover, short term price fluctuations are also seemingly larger for EMPS. Generally, a smoother curve, more like ProdMarket's, is considered more realistic, in that a hydropower-dominated system, if run correctly, should be able to even out most short-term load and inflow variations. This reasoning is based on an energy perspective: Whether or not daily or hourly load levels are high should not affect water values significantly as long as there is enough water to plan ahead in the long run (remember that water values are correlated to expected future cost). In a way, this can be seen in the price plots too – short-term fluctuations vary more during months where inflow is limited and as such the system is more heavily affected by small changes in load and inflow. There are some limitations to this line of thought, however. The first is that long term energy planning is not relevant if the system is short on production capacity in the short term – a scenario that is not unlikely to occur in future power systems where intermittent power sources cover most of the base load. Conversely, periods of surplus generating capacity can occur when intermittent production surpass demand levels, causing zero or even negative price levels; this has already been observed in some continental power grids (Schaps & Eckert, 2014). For our system, however, short term generating capacity is normally not a problem – as long as enough reservoirs have water left in them – at least not for the base case. The second aspect that affects whether or not seasonal and weekly price variations should be considered good, or realistic, is stochasticity. In the real world, a short-term drop in precipitation influences not only the current planning period, but the time-correlation of inflow means that it could very well be the start of a drier than usual filling season. How the models consider the time-dependency of system inflow affects the overall yearly shape of both their price curves and magazine level plots. As was done for the magazine levels, we will now take a look at some price percentile plots, one for each model.

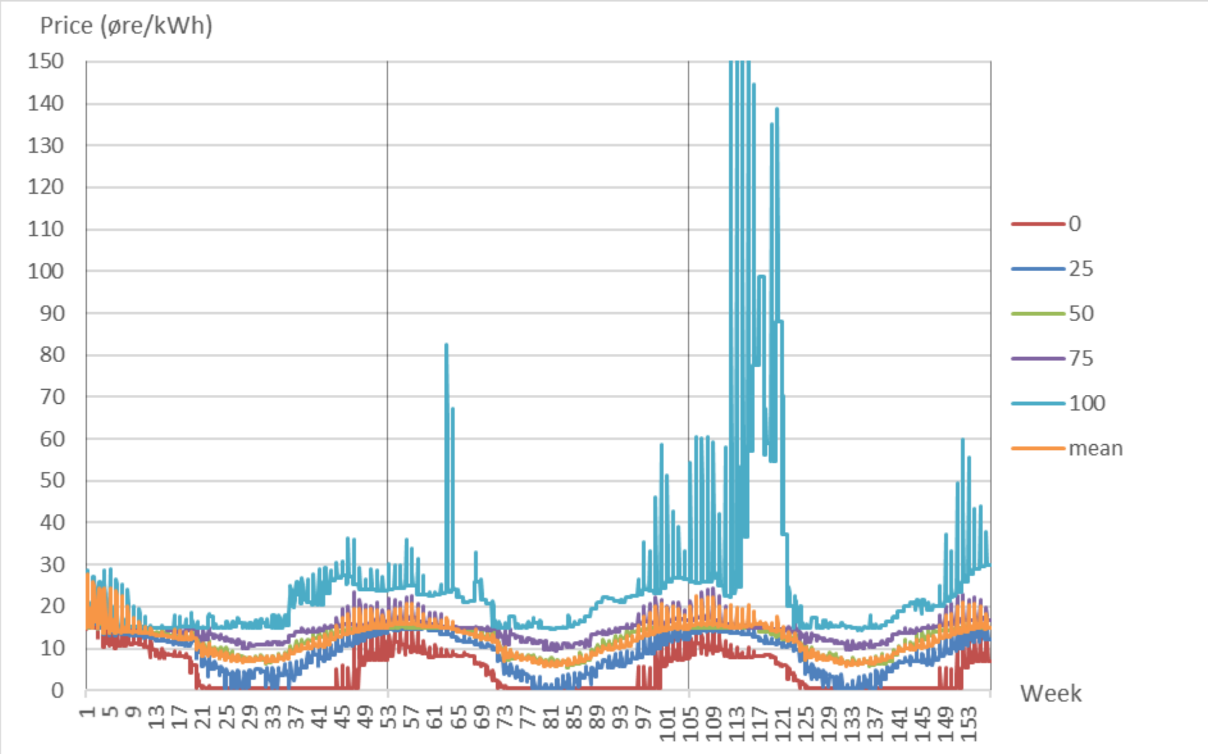

Figure 22 - Base Case power price, percentiles. EMPS. [24,25]

EMPS's mean price curve from Figure 21 is plotted in Figure 22 as well, in orange. It almost completely covers the green 50-percentile curve; indicating that price scenarios are somewhat evenly distributed on the upper and lower side of the mean. The other percentiles form an approximate representation of the spread of the 50 inflow scenarios. Note again that no scenario looks exactly like the percentile curves above: They move up and down between percentiles. The second line from the bottom, the 25-percentile, shows that in some wet summer weeks, a full quarter of the inflow scenarios lead to price periods where the price drops close to zero – this indicates that load can be supplied solely by producing from magazines that are nonetheless completely full of water. As for the top quarter, prices generally lie very close to the 50-percentile. There are, however, some distance between the 75-percentile and the extreme cases represented by the 100-percentile. Especially during the winter between the second and third year, there are large weekly fluctuations in the very highest prices. This is likely the main contributor to the variations seen in the mean price at this time – just one or a few extreme cases where prices multiply several times or even reach

[24] Price axis cut at 150, highest values reach 450 øre/kWh.

[25] EMPS power price is from the "Numedal" area after verifying that differences between areas were negligible.

the rationing cost of 450 øre/kWh is enough to make a considerable impact on the mean. This turns out to be the case also for ProdMarket. Its percentile plot is shown below, in Figure 23.

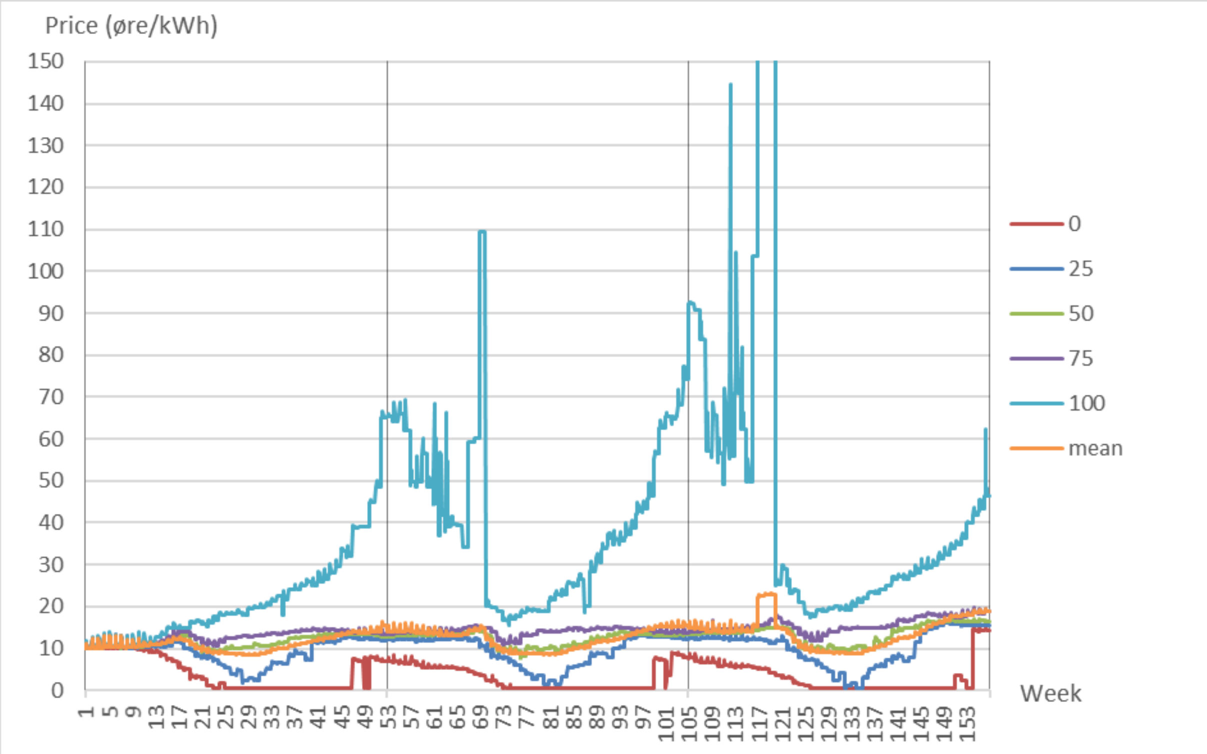

Figure 23 - Base Case power price percentiles, ProdMarket. [24]

Compared to EMPS, ProdMarket has a higher number of weeks where a few extreme cases pull the mean upwards – in one case the mean even surpasses the 75-percentile by some margin; this is the period where the 100-percentile reaches rationing cost, and stays there for some weeks. Apart from the extreme cases, however, the main bulk of scenarios, from the 25- to the 75-percentile, show very little variation. Simultaneously as the extreme price peaks are observed, most of the other scenarios are concentrated in a small price band between twelve and 15 øre/kWh. The overall picture also clearly shows that ProdMarket has less short-term fluctuations than EMPS – all curves are smoother and more consistent.

6.2.4 Pumping potential: Short-term price fluctuations

One of the reasons why this thesis runs simulations with 16 price periods (as opposed to four, or just one) is that inter-weekly fluctuations can be illustrated better. The price points are furthermore chosen in such a way that they approximate two 24-hour days of the week: One weekday and one weekend-day. The below plot is created by averaging all prices in a given price point over the entire simulation period: Figure 24 show 24-hour price profiles for the two days made up by the price periods.

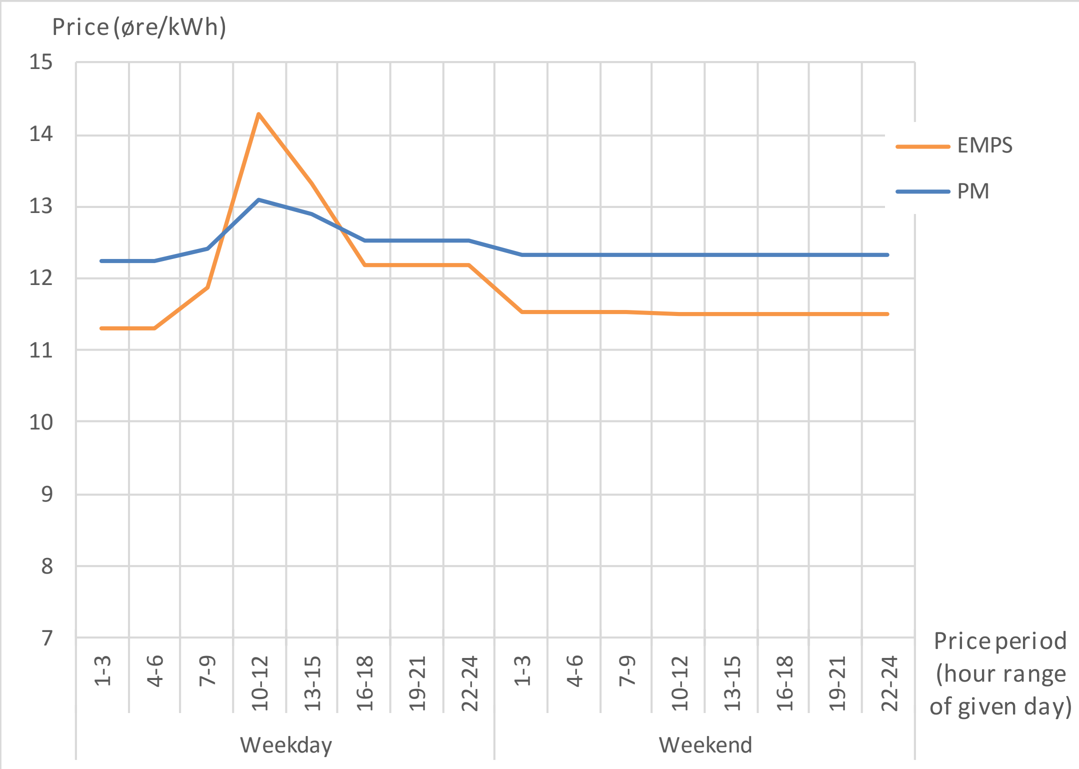

Figure 24 – Mean price profile, all price periods. EMPS and ProdMarket. Base case.

Note the start of the Y-axis in Figure 24: Price fluctuations are generally very small! First of all, the weekend (on average) has identical prices for all price periods. For the weekday, there is a trend that the time-span from 10 to 12 am sees the highest prices, while the night and early morning has the lowest prices. Notably, variations are considerably larger for EMPS than for ProdMarket. The reason for this is unknown; it could be that ProdMarket is better at evening out price variations due to more detailed water handling, or the use of a price model in the sub-are calculations somehow smooth out power prices.

Figure 24 the price profile the planning model calculates and outputs. But it also holds the building blocks required to visualize a full average weekly profile: Figure 25 below is created by repeating the “Weekday” and “Weekend”-profiles five and two times, respectively. Although no new data is added, this is a highly intuitive visualization when considering the full time sequence of price fluctuations.

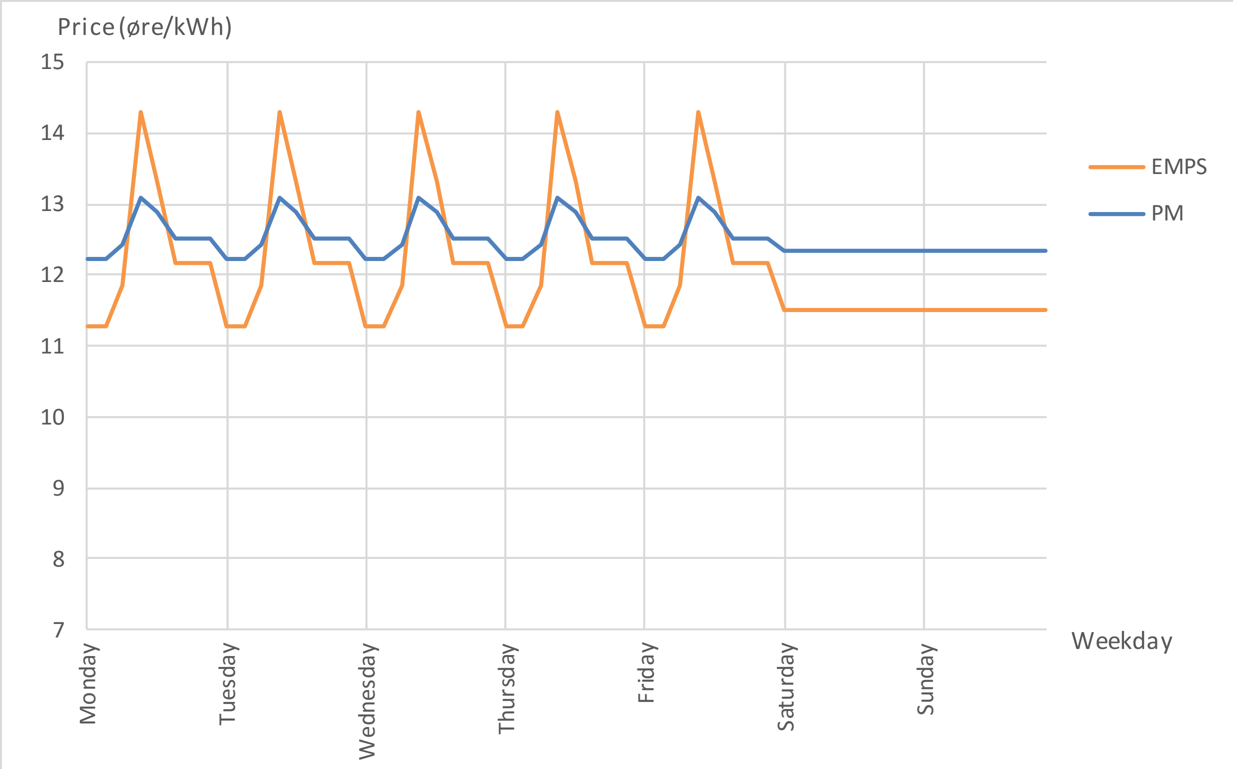

Figure 25 - Weekly price profile. EMPS and ProdMarket. Base case.

This simulation case does not include pumped storage, but we can nonetheless look for indicators of whether or not inter-weekly pumped storage would have been viable. Remember from Section 2.2.5 that pumped storage generally requires price fluctuations of roughly 25 % in order to consider economic viability. If anything, let us consider day/night pumping using the EMPS model's price curve: The highest mean price is 14.3 øre/kWh in the fourth price period, the lowest 11.3 øre/kWh in the first and second price period, a difference of just under 27 %. Averaging the weekday and weekend-profile, the overall mean price difference is reduced to roughly $\frac{2*0+5*27[\%]}{7[\text{days a week}]} = 19$ %. This indicates that there might actually be some viability in inter-weekly pumping such as daily pumping sequences, at least for the weekdays. However, we are already aware that EMPS handles pumped storage in a somewhat simplified way, and so even if a pump was present, the usage might have been limited – a subject to return to in the future cases. Using ProdMarket's price curve, however, the largest weekday price difference is a mere 7 % between the same hours (prices are 13.1 øre/kWh and 12.2 øre/kWh, respectively), only 5 % for the average daily profile. Comparing this to actual price fluctuations in Norway, Statnett (2014, p. 20) plotted a graph showing a somewhat similar price profile: A price increase of about 15% percent was observed from the early morning (hours 3-5) to the higher price level of the day (somewhat stable for hours 9 through

22). In this respect, a level in between the price variations of ProdMarket and EMPS could be considered correct, but this is for Norway as a whole and might not be right in our system.

Figure 24 is of course just an average power profile. Some aspects, such as the random fluctuations in wind production, is barely captured by this figure: Only the daily trend of wind production is captured – a trend that is generally weak (as the wind also blows at night, unlike e.g. PV production). To reveal whether there was underlying dynamics that were not shown in the figure, two more curves were studied. Both considered a single week, to ensure that no time-average would even out fluctuations. The (randomly) chosen week was week 78, the 26th week of year two (i.e. an early summer week where water shortage is not an issue, while the highest inflow peak has not yet hit). First, a percentile graph was plotted for each of the models; very little price variation was observed (virtually none for ProdMarket). Second, a single inflow scenario price was plotted, further ruling out the risk of removing variance by using percentile plots; no price variance was observed whatsoever. These are only one week, and one inflow scenario, out of many, but the trend is clear:
Short-term price variations are generally small, especially for ProdMarket, both for the average profile and for the individual scenarios.

6.3 Scenario A – Small storage

Moving on to the first of the two future scenario case studies, based on the HydroBalance project's "Small storage" scenario, the first thing we will look at is whether the EMPS model's calibration still provides sound magazine handling. The calibration setting, "Manual 2", from section 4.1.1, was first developed for the Base case, but was assumed suitable for the future scenarios as well. To check this hypothesis, EMPS's magazine handling for each of the simulated waterways are studied. Plots show very similar magazine handling as in the Base case; the most notable differences are slightly higher magazine levels in the Numedal and Otra waterways, which is acceptable(Figure 75 through Figure 77 in Appendix A). To conclude, then, the calibration setting is kept as is.

After completion of the below analysis, a typo was found in the calibration implementation. Instead of being identical to the Base case calibration, one of the calibration factors had been accidentally changed: The elasticity factor for the TEV waterway was set to zero, not one, as intended. The results presented below, therefore, is based on a slightly different calibration setting than in the other two simulation cases. EMPS has been re-run to check applicability of the results; observed differences were negligible. The below results and analysis are hence kept as is. For reference, the main results from the corrected EMPS run are shown in Appendix H.

6.3.1 Overall results

First things first: Observed economic results for Scenario A for ProdMarket were remarkably bad compared to EMPS and the Base case. Whereas in the previous simulation case ProdMarket outperformed EMPS by roughly 57 MNOK, this relationship was flipped upside down as initial results showed a massive gap in excess of 240 MNOK between the models, in EMPS's favour. As will be detailed further down, however, it turned out that a difference in ET's results calculations between the models meant that a 134.4 MNOK income could be subtracted from EMPS's results to maintain comparability to ProdMarket. Nonetheless, EMPS provides results roughly 108 MNOK better than ProdMarket. This is unexpected, considering the good results in the Base case and the positive trend observed in Kyllingstad (2015) as price volatility was increased. Even with the correction, Scenario A results have drastically changed the balance between EMPS and ProdMarket. In the following paragraphs, we will look for contributing factors and signs as to why and how the results have changed so drastically.

Table 21 below is the Scenario A equivalent of Table 20 in the previous subsection. It summarizes energy- and economy-related results from EMPS and ProdMarket. As in the Base case we will now go through the results, doing quick comparisons to the previous case and between the models as we go. This time, however, not all rows or details of the table will be discussed in great detail; refer to section 6.2 for a more comprehensive explanation of the individual elements of the table.

Table 21 - Results for Scenario A for EMPS and ProdMarket. Mean values. Numbers are total over 156 weeks.[26]

		EMPS					ProdMarket
	Unit	Numedal	TEV	Otra	Term	**Total**	
Inflow	GWh	9315.7	7360.4	11086.1		27762.2	28078.7
Spillage and bypass	GWh	561.7	707.3	658.2		1927.2	1594.3
Pumping, use	GWh			450.6		450.6	703.6
Pumping, gain	GWh			646.8		646.8	947.7
Pumping, net	GWh			196.2		196.2	244.1
Start magazine, sum	GWh	1070.8	1125.0	2003.9		4199.7	4199.7
End magazine, sum	GWh	884.8	1084.4	2333.4		4302.6	4743.3
Contracted power demand	GWh	8985.0	6547.5	9900.0	1230.0	26662.5	26662.6
Delivered hydropower	GWh	8940.0	6693.8	10294.6		25928.4	26185.0
Contracted power not deliv.	GWh	0.5	0.2	0.6	0.0	1.3	24.2
Interruptible load bought	GWh	122.8	0.0	156.2	496.2	775.2	1436.6
Interruptible load sold	GWh	875.3	29.9	433.1	29.9	1368.2	996.0
Wind power, Norway	GWh				1326.0	1326.0	1326.0
UK wind and GE PV, net	GWh				-0.1	-0.1	-0.1
Contracted power not deliv.	MNOK	-0.3	-0.2	-0.4	0.0	-0.9	-30.9
Net interruptible load	MNOK	11.6	7.4	22.5	-68.0	-26.5	-156.2
Net income*	MNOK	41.2	-15.8	104.2	-157.0	-27.4	-187.1
Magazine level changes	MNOK	-21.2	-6.7	28.1		0.2	51.8
Net income, magazine adj.*	MNOK	20.0	-22.5	132.3	-157.0	-27.2	-135.3

We remember that the Scenario A data set, based on the “Small storage” future scenario, introduces an opportunity to use pumped storage hydropower to balance seasonal and short-term fluctuations in load and production. At a glance, Table 21 tells us that this has increased the total power used to pump water for both models. And contrary to what the economic numbers alone show us, there are still signs that ProdMarket does a good job at some aspects of the scheduling problem. In the Base case, both simulation tools recommended using the standard “non-reversible” pump station almost exactly the same; totalling around 120 GWh over the simulation period. This time, EMPS uses just over 405 GWh to pump, and ProdMarket over 700 GWh. This indicates some use of the new reversible pump, and notably, that ProdMarket manages to find use for it more often than EMPS. This is, in a way, as

[26] The * in the final row refers to a correction made to the EMPS numbers: Wind power income has been subtracted to maintain comparability to ProdMarket. For Scenario A, this was 134.4 MNOK.

expected, as ProdMarket, through ProdRisk, has much better algorithms for optimizing use of reversible pumps than EMPS does; EMPS uses a simplistic rule-based approach (as discussed in section 4.1, page 27), whereas ProdRisk has a complete set of future cost functions helping it distribute water between specific reservoirs.

Looking at the first two rows of the above table does not reveal any weak points either. ProdMarket still manages to utilize more of the available inflow; both the inflow figure and "Spillage and bypass" is higher for ProdMarket than for EMPS. In other words, even though the gap between the models is not as large as in the Base case, ProdMarket still shows superior handling of individual magazines as it manages to operate its system with significantly less spillage and bypass flows than EMPS. Where, then, does the poor economic results come from? There are some hints found further down in Table 21. One of them are ProdMarket's increased use of rationing and repurchasing of load ("contracted power not delivered" in the table), up from around 12 to 24 GWh – more than doubling these costs from 15 to 31 MNOK, while EMPS now uses less than a million. This difference between the models contributes 30.0 MNOK to the net economic numbers. Nonetheless, there has to be other, larger, factors explaining the remaining economic difference between the models. The very next rows of the table give clear clues. Take a look at the row named "Interruptible load bought" in Table 21; this is all energy bought on the simulated power market, i.e. energy that comes at cost. In the case of the EMPS model, this post is more than halved from over 1600 GWh to well below 800 GWh. Meanwhile, ProdMarket has increased its need for power sources such as thermal power and spot-market transactions by more than 100 GWh to roughly 1437 GWh. Conversely, looking at the next row in the table, representing the amount of power *sold*, ProdMarket's amount is decreased by more than 60 GWh while EMPS increases this post by almost 170 GWh. All in all, ProdMarket now buys $1436.6 - 996.0 = 440.6$ GWh of additional energy over the course of 156 weeks. EMPS does the exact opposite, and sells a surplus $1368.2 - 775.2 = 593.0$ GWh of energy. Surely this has to account for a large portion of the economic gap between the models? Indeed, the row specifying the economic impacts of trade in interruptible load shows that EMPS almost manages to "break even", with only 26.5 MNOK in costs, as compared to ProdMarket's massive cost of 156.2 MNOK. The gap between the models, just shy of 130 MNOK, is in itself enough to more than account for the difference in net adjusted income (which was 108 MNOK).

Before the net result correction was applied, initial (not magazine adjusted) net results showed that EMPS had 294.1 MNOK higher results than ProdMarket. Now, backtracking these results showed that something was missing: Removing the 30.0 MNOK due to differences in "Contracted power not delivered" and 129.7 due to "Net interruptible load", left $294.1 - 30.0 - 129.7 = 134.4$ MNOK missing. This number was then identified as a wind energy income that was only included in EMPS's results. The difference in result calculation is thought to come from the early "ad-hoc" implementation of wind currently used in ProdMarket, where wind power does not show up in any user interface. Double-checking the Base case results showed that no such income was present there (so no correction was necessary); this is presumably because the limited scale of wind power implemented there did not provide a power surplus that could be sold to generate an extra income.

With the net income correction in place, the $187.1 - 27.4 = 159.7$ MNOK difference in "Net income" result between the models can be neatly summed up by adding rationing and "interruptible load"-costs together: $30.0 + 129.7 = 159.7$ MNOK. The magazine level adjustments is then what decreases the net *adjusted* gap between the models to $135.3 - 27.2 = 108.1$ MNOK. Considering for a moment the specific costs level indicated by the models, and comparing them to the Base case, the future system represented by this scenario seems cheaper to operate. Letting EMPS be the judge, it runs this system over 140 MNOK cheaper than it does "the present system" represented by the Base case (Base case net adjusted income was -170.1 MNOK for EMPS). The lowered system costs are considered a direct result of the more than tripled energy contribution from "Norwegian" wind power, now up to 1326 GWh over the simulation period or 442 GWh per year. The improved energy balance provided by the free wind power decreases the amount used for thermal power and other costly alternatives to wind and hydro (the models see no operational costs related to wind or hydro power). Hence, ProdMarket's 22 MNOK increase in cost levels merely serve as a reminder that modelling tools will have to be thoroughly tested and cross-checked as power system strain increases.

6.3.2 Magazine handling

As in the Base case discussion, we will now take a look at some overall magazine and price graphs to supplement our discussion of the overall energy and economic results. Figure 26 below shows sum reservoir levels for Scenario A – "Small storage" – for both simulation tools.

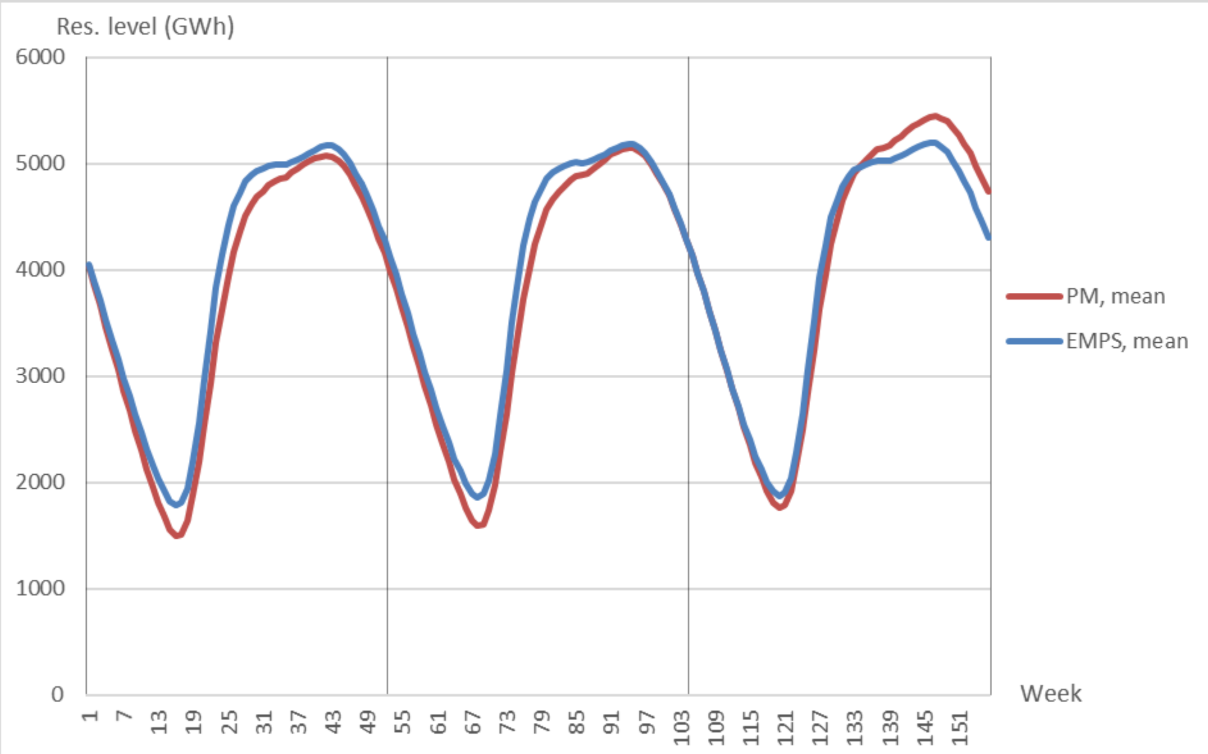

Figure 26 - Scenario A sum reservoir level, mean. EMPS and ProdRisk. [27]

As we did in the Base case simulations, we observe from the mean sum magazine plot that ProdMarket has a tendency to "stock up" on water during the last summer and fall. Again, this is thought to come from an overly optimistic end valuation of water (or rather: overly pessimistic, as higher water values would likely result from tougher operational conditions). Apart from the last few months of simulation, the two models once again show similar yearly profiles. Looking at Figure 26 alone, there is very little indication that ProdMarket has lagged behind EMPS in terms of operational soundness; the drop in economic results are apparently not related to overall magazine handling.

We move on to take a look at the magazine percentile plots. Based on the sum reservoir percentiles as plotted in Figure 27 below, the EMPS model generally manages to run its

[27] EMPS sum reservoir level is calculated as the sum of the sum reservoirs in each of the three waterways.

system with a comfortable buffer between it and rationing. The 0-percentile is tuned so that it just barely avoids rationing; this indicates good, careful use of available magazine capacity.

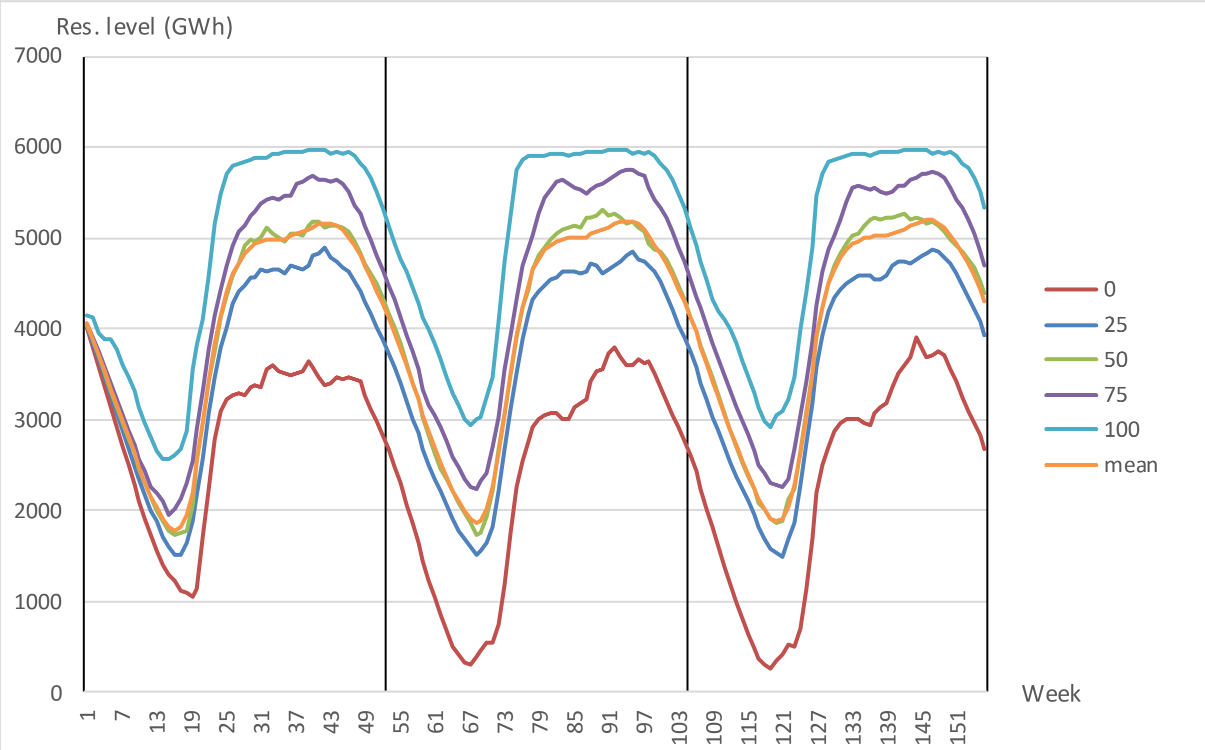

Figure 27 - Sum reservoir level, Scenario A, EMPS. Percentiles.

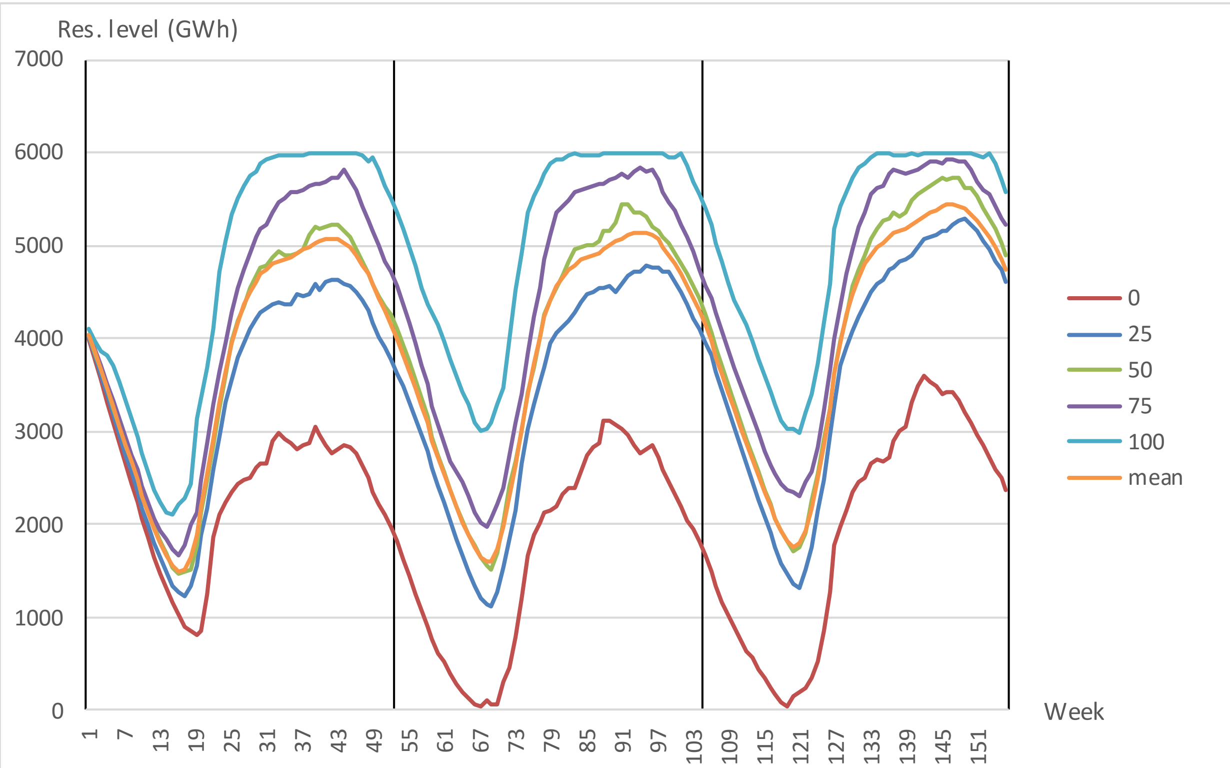

Figure 28 - Sum reservoir level, Scenario A, ProdMarket. Percentiles.

Overall, the magazine percentile plot for ProdMarket, Figure 28 above, is not very different from that of the EMPS model. There are some minor differences, however. As the mean level comparison in Figure 26 suggested, ProdMarket runs its system slightly harder than EMPS; every winter, the water level is allowed to drop just ever so slightly lower than for the EMPS; this seems to apply to all percentiles. Not to say that system operation seems obviously flawed: Although ProdMarket causes slightly more rationing than EMPS (which shows almost none), the level is acceptable and was, as discussed previously, just enough to explain a small portion of the difference in economic results. Were it not for the poor economic results of ProdMarket, these results could very well have been used as an explanation why ProdMarket is indeed slightly better than EMPS at utilizing all available magazine capacity. And, as the results in Table 21 revealed, ProdMarket still shows superior handling of individual magazines, losing significantly less water to spillage and bypass flows than EMPS does. The conclusion remains that the drop in economic results are not obvious looking at magazine handling, whether overall or individual handling is considered. Perhaps the below price plots will provide more clues.

6.3.3 Power price

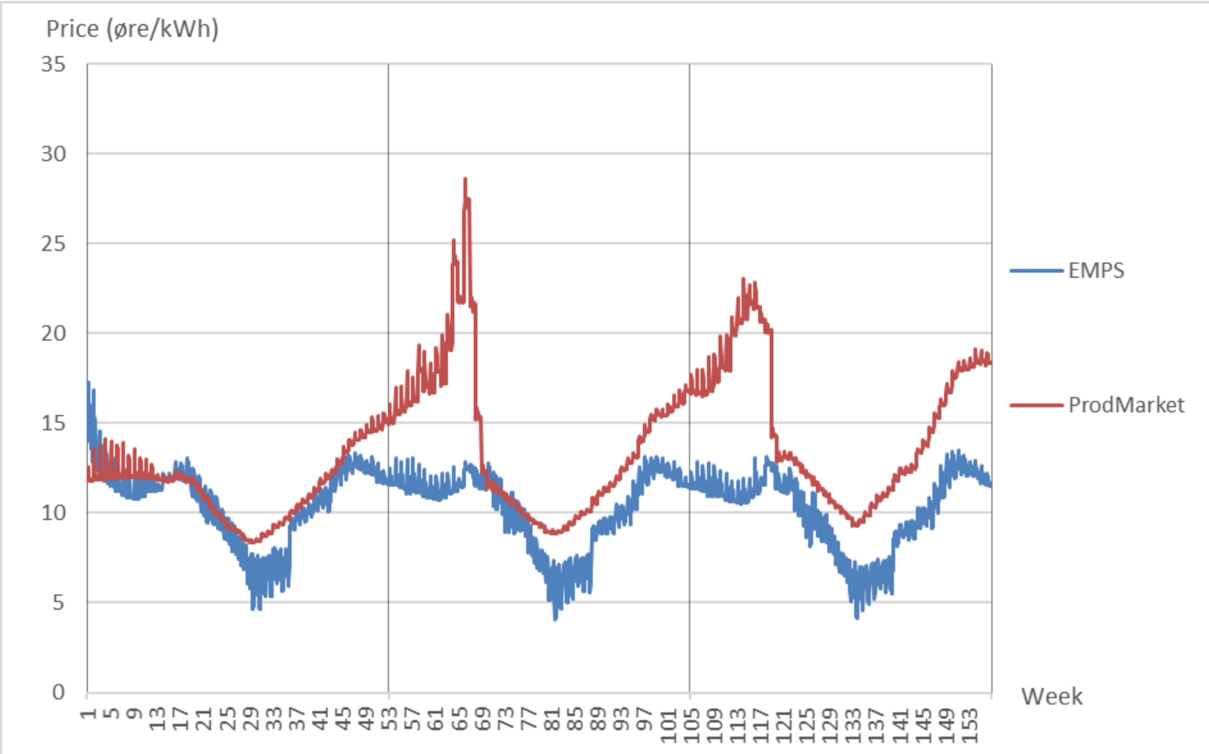

Figure 29 - Scenario A power price, mean. EMPS and ProdRisk. [28]

[28] EMPS power price is from the "TERM" area. Differences between areas were checked and found negligible (less than 0.01 øre/kWh).

Figure 29 shows mean power price curves for both our models. Looking at the plots, the most striking thing is how much higher ProdMarket's winter price peaks are compared to the EMPS model. Whereas in the Base case, EMPS generally showed equally large seasonal price variations as ProdMarket, and considerably more short-term fluctuations, the two models now operate on completely different price levels. For almost the entire discharge seasons, from roughly weeks 40 through to 70 and 92 through 122, ProdMarket's price levels are considerably higher than EMPS's. But the overall price level is also higher; even the summer prices are higher in ProdMarket than in EMPS. Calculations show that the average simulation period prices are 13.4 øre/kWh for ProdMarket and 10.3 øre/kWh for EMPS. This is a significant gap, and is a tell-tale sign that ProdMarket's increased spending on interruptible loads result in higher system costs. Nonetheless, ProdMarket still has less short-term fluttering in power prices than EMPS for most of the simulation period. We are curious to see if the percentile-graphs can tell us more.

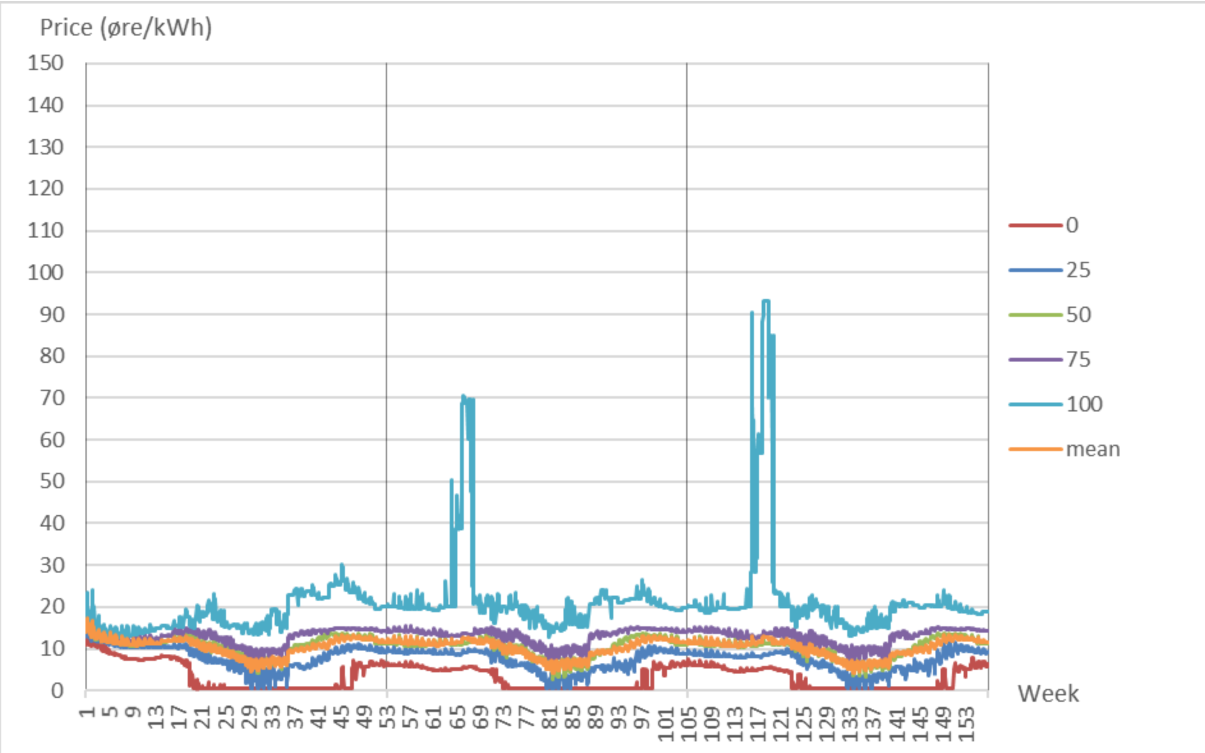

Figure 30 – Scenario A power price, EMPS. Percentiles. [29]

Looking at Figure 30, EMPS shows relatively little distance between inflow scenarios; keeping the Base case calibration for this "Small storage"-scenario seem to have led to relatively careful system operation. More specifically, we note very modest extreme values:

[29] EMPS power price is from the "TERM" area. Differences between areas were checked and found negligible.

Even the 100-percentile never reaches values close to rationing cost; as expected from the economic results.

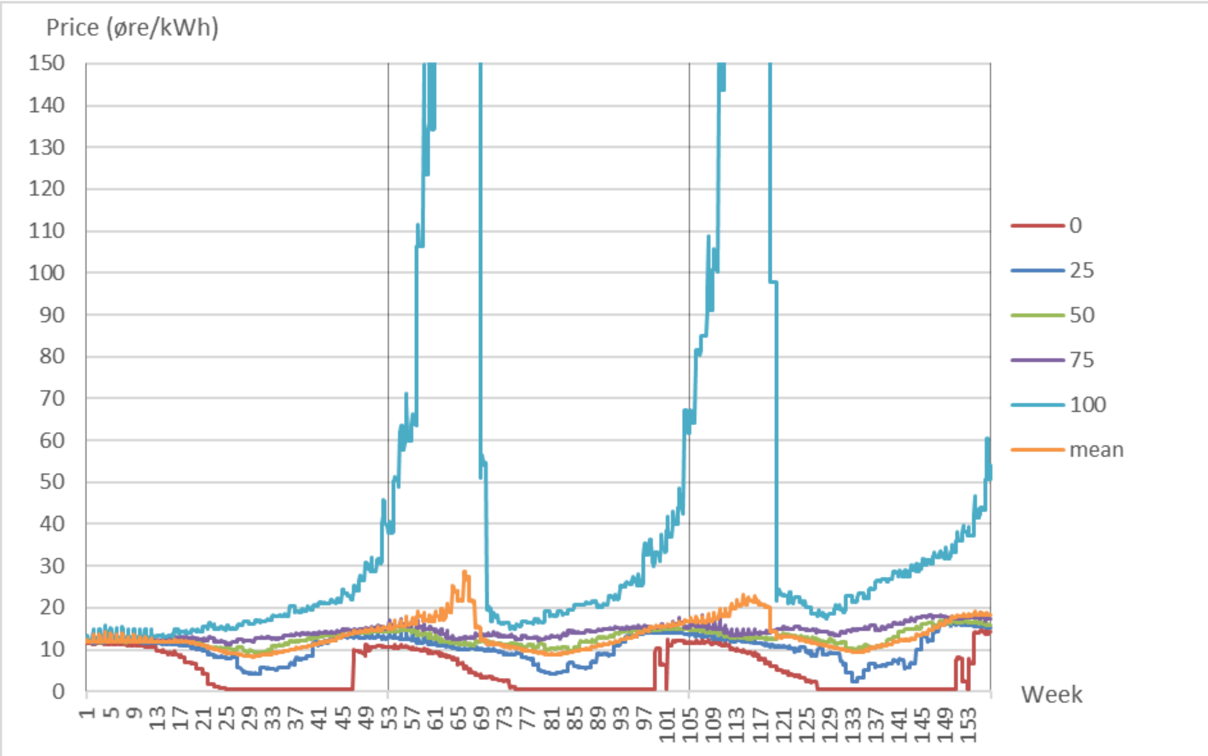

Figure 31 – Scenario A power price, ProdMarket. Percentiles. [30]

The ProdMarket percentile graph, Figure 31, shows a completely different story in terms of extreme values: The 100-percentile graph surpasses 150 øre/kWh and rockets towards rationing cost for considerable periods both second and third year winters. The mean is, as we have already seen from the mean comparison graph in Figure 29, also heavily affected by these extreme values: It is, at times, twice the value of the 75-percentile line. Not considering the extreme values of the 100-percentile and the mean, however, the other percentiles are very closely aligned. This means that apart from a few outliers, most inflow scenarios give prices at reasonable levels, comparable to the EMPS model, where the risk of rationing is seemingly very low.

6.3.4 Pumping

This subsection starts off with discussing short-term price fluctuations, as in the Base case. Subsequently, this is used as a backdrop to discuss the observed pump use.

[30] Price axis cut at 150, highest values reach 450 øre/kWh.

Short-term price fluctuations

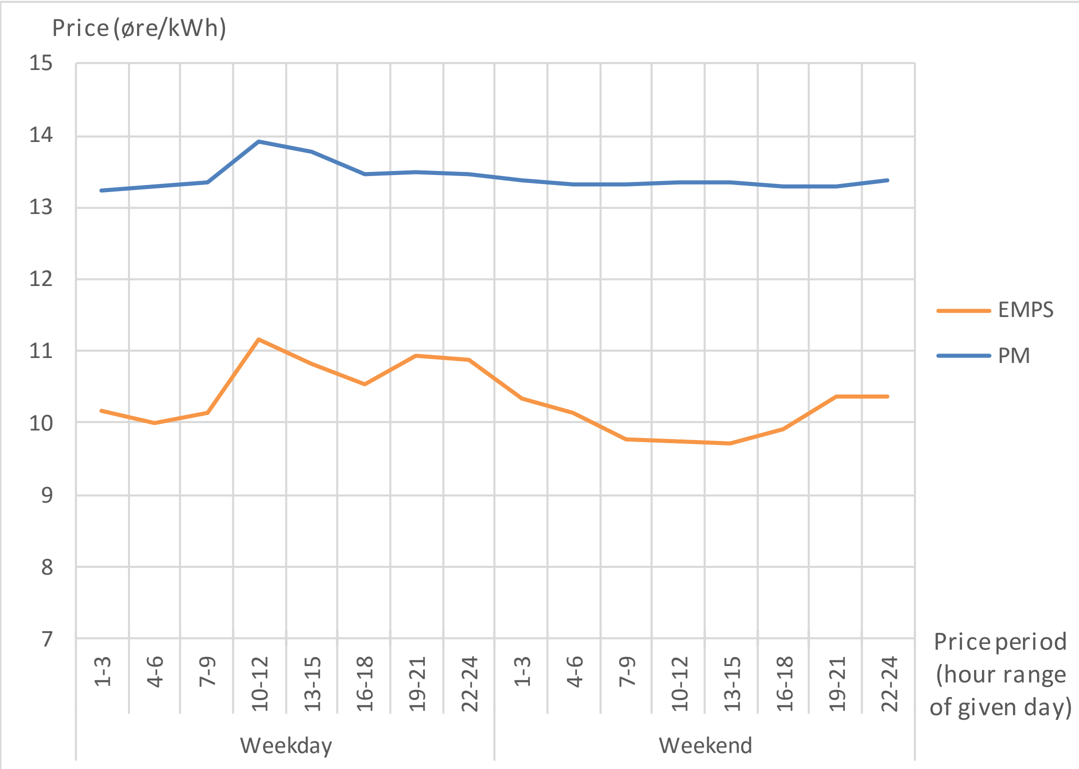

Figure 32 - Mean price profile, all price periods. EMPS and ProdMarket. Scenario A.

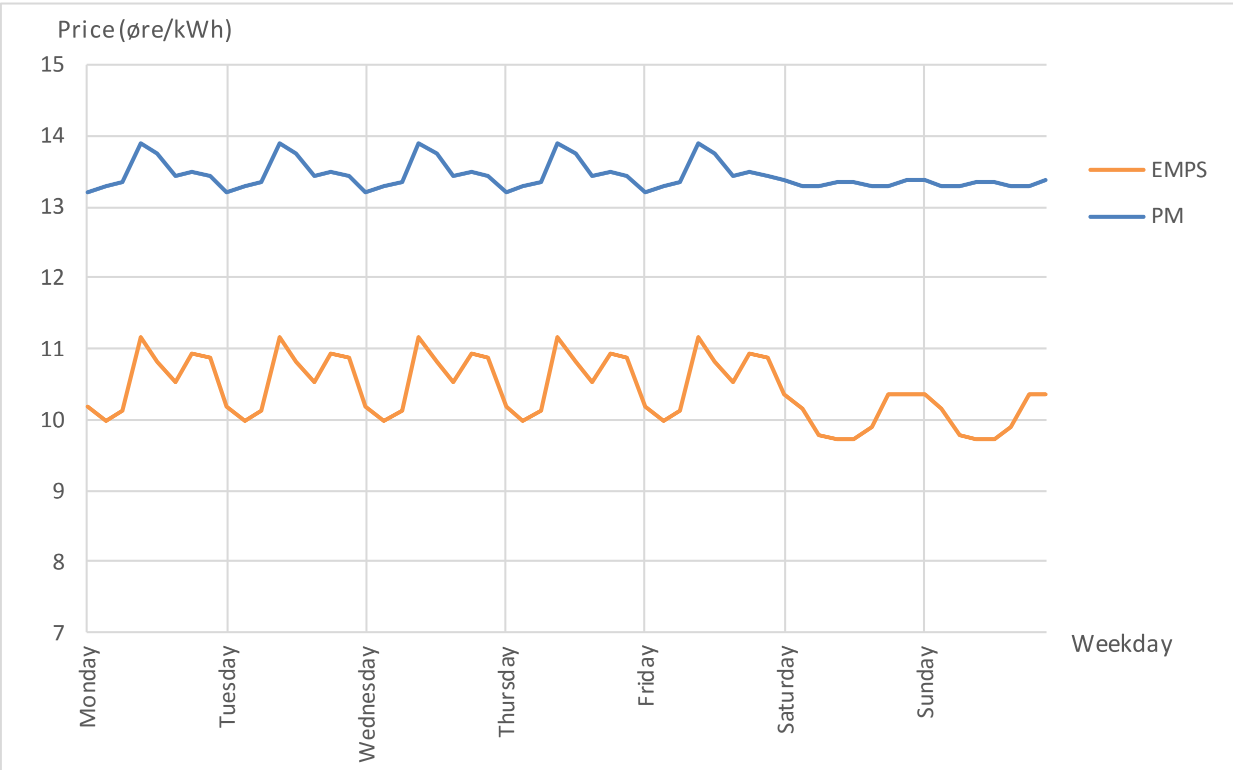

Figure 33 – Weekly price profile. EMPS and ProdMarket. Scenario A.

Figure 32, above, shows the average price profile for all 16 price periods for each of our two models. The two daily profiles are used to create a weekly profile, Figure 33. Once again, EMPS shows more daily fluctuations than ProdMarket. The ProdMarket profile is almost completely flat, price variations over the week is within roughly 5 %. For EMPS too, the price variations have decrease from the Base case, now down only 11 % during weekdays. What is new, however, is the slight drop in prices during daytime in the weekend. This is interesting: It is presumably directly correlated to the daily production peak from the German PV capacity. Including this price drop, the weekly average price spans from 9.7 øre/kWh during early afternoon on weekends to 11.2 øre/kWh during late morning on weekdays. Nonetheless, the price difference is only roughly 15 percent, down from 27 in the Base case. This is perhaps the most surprising observation: That all the new intermittent energy has not increased, but decreased, the daily and weekly price variations.

As for the Base case, week 78 was chosen as a "random sample" to study a bit closer, possibly revealing variations hidden by the mean weekly profile. For inflow scenario one, variations were once more very small. No further effort has been made in this thesis to pull out single scenario results – this is commented as a possible field of future work in Section 7.1.

Reversible pump usage

Scenario A introduced a reversible pump turbine of 360 MW to our modelled system. From the above discussion on short-term price fluctuations, there does not seem to be a consistent potential for intra-day or intra-week pumping in our studied system; whether the price fluctuations are 5 or 15 percent, this is not enough to warrant running a reversible pump. There could, however, be a number of scenarios where pumping is warranted, only that the mean does not show it. Moreover, there could still be potential for weekly, monthly or seasonal pumping. Indeed, the overall results discussed previously showed us that the pump had been used to some extent. The following graph will, perhaps, help us understand how: Figure 34, below, plots mean production or pumping from the reversible turbine over the course of the second simulation year (EMPS in blue, ProdMarket in red). Only one year is plotted to allow for some detail to be visible; the second year is chosen based on previous discussions on how it is the least affected by the boundary conditions of the simulation period. As for the price variation plots, we risk losing variability when using mean plots; Figure 35 plots inflow scenario 1 to exemplify how the actual scenario plots differ from the mean. The

X-axis shows weeks, but the resolution is price periods, so there is no time-averaging. The Y-axis exactly covers the production range of the reversible turbine: +360 MW to -360 MW.

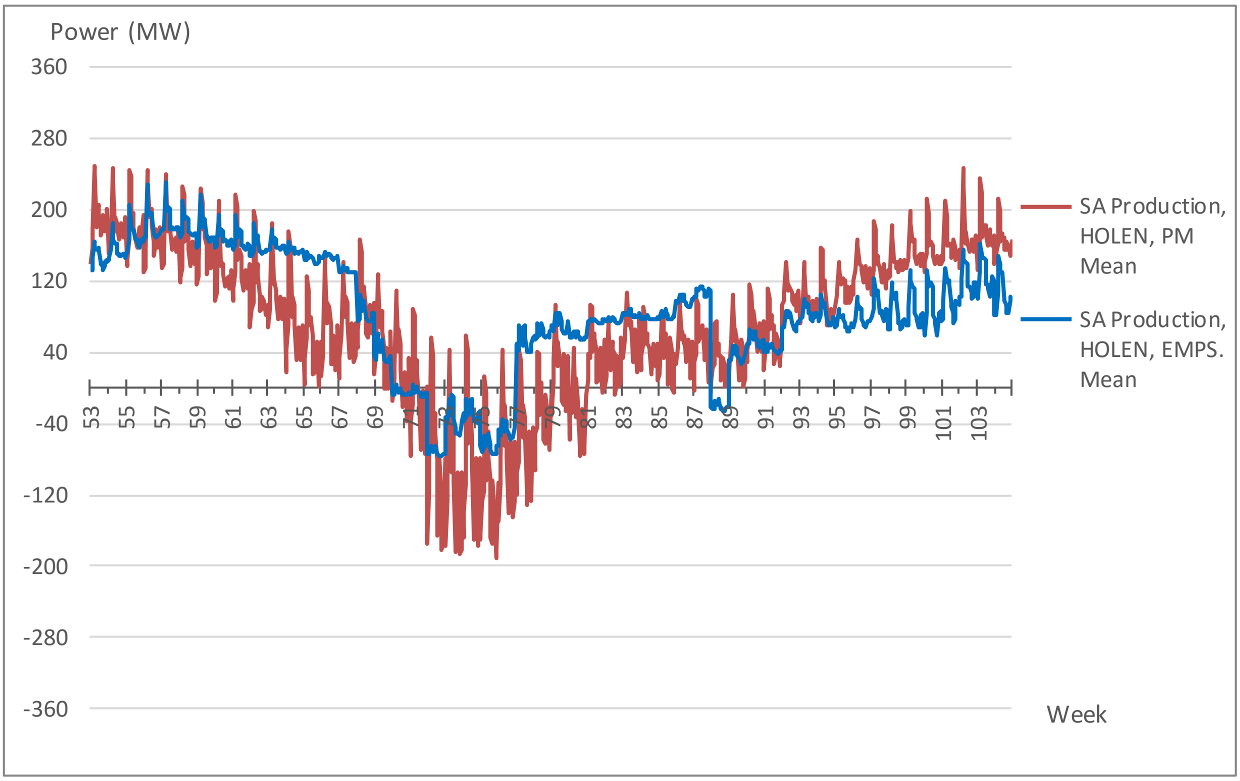

Figure 34 – Mean production and pumping, Holen power station, Scenario A. ProdMarket and EMPS. Negative numbers are power used for pumping.

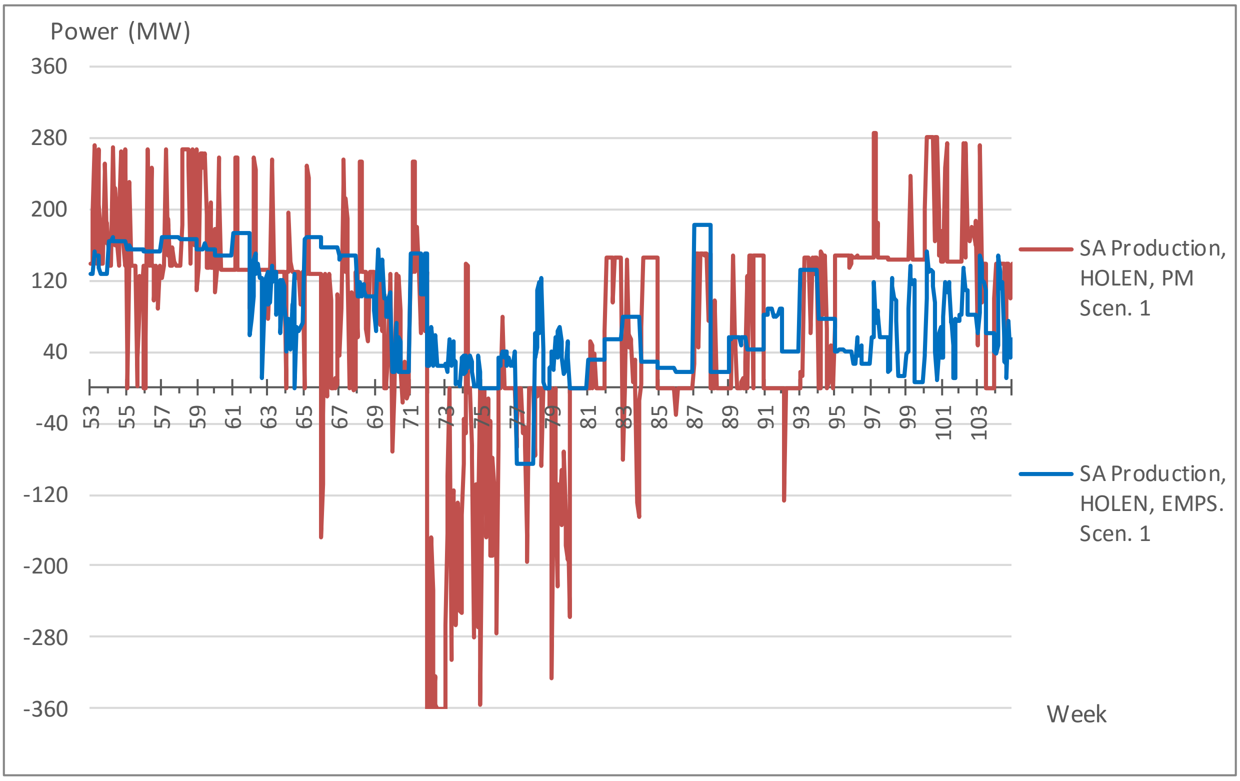

Figure 35 – Inflow scenario 1 production and pumping, Holen power station, Scenario A. ProdMarket and EMPS. Negative numbers are power used for pumping.

First of all, we can note that the mean in Figure 34 is reasonably representative for the inflow scenario in Figure 35. In practice, this presumably indicates that "random pumping" based on short-term fluctuations in renewable energy is limited. This follows from the fact that the mean does not reflect such pumping, and so if its presence was great, the mean should differ greatly from the inflow scenario (of course, there could be other inflow scenarios where this is more evident). Secondly, ProdMarket and EMPS follow surprisingly similar yearly trajectories. Production is high during winter, gradually moving toward some limited pumping during early summer, somewhat more for ProdMarket's curve. One important reason for the general shape of the curves is that there is considerable inflow that "must" be produced. Roughly a quarter of the Otra waterway's volume inflow falls above the Holen power station where the reversible pump is located – this means that the mean curve will be heavily affected by the inflow and demand variations in the system. Had the reversible pump been installed at a location with very little inflow, the characteristics of the reversible pump itself would have been more evident. Nonetheless, the overall shape of the pump/production curve suggests that seasonal pumping could be the most relevant.

The most evident difference between the models is the size of the weekly fluctuations in production level. ProdMarket has significantly more variation between single price points and between weeks, both for the mean and the inflow scenario plot. This shows that, although only a limited number of price periods has the power station change over to pumping mode, more of the available production capacity is utilized. This is visible from the single inflow scenario plot: Instead of producing at an almost constant level, power production is more focused towards single price periods, presumably the periods where the power price is the highest. This could also be an important reason why ProdMarket has lower power price variation: Production variation is used as a means of balancing, effectively limiting price variations as long as the "marginal unit" has spare capacity. In economy, the marginal unit is the unit with the highest production cost amongst the currently producing unit; it is said to "set the price". Remember that for hydropower units, the water value acts as a marginal cost. In the case of stored hydro, there is also the added complexity that the water value decreases or increases *during* production, as the water level rises or lowers, respectively.

It is unclear why, in Figure 35, the production seems to drop to a set level in between periods of high production (see weeks 60-66), but there are several possible explanations. First, the "middle level" of around 130 MW is, perhaps, roughly the level required to compensate for inflow. On a more technical level, it could also be that the recurring plateaus observed represent the intersections between different cuts used to describe the future cost function (i.e. water value). A third option is that it corresponds to the production plant's peak efficiency point. This is quickly tested by plotting Figure 36 below, which shows Holen production plant's efficiency curve. The numbers adjacent to the curve is the corresponding production output. 130 MW is clearly no global or local max-point in efficiency, so the third theory can be de-bunked. Moreover, comparing to Figure 34, there is no such set level, so it seems any recurring production levels vary with the inflow scenario. It is also unclear why not a single price period uses the full capacity of the power plant. It could just be that there is no need for such large capacity, there might be more efficient plants or plants with lower water values that are used to cover base loads, so that this plant produces on a reduced level. In a way, the decreasing trend in Figure 36 below suggests that, form an energy perspective, the plant's output should be kept "as low as possible" once the threshold of 85 MW is surpassed.

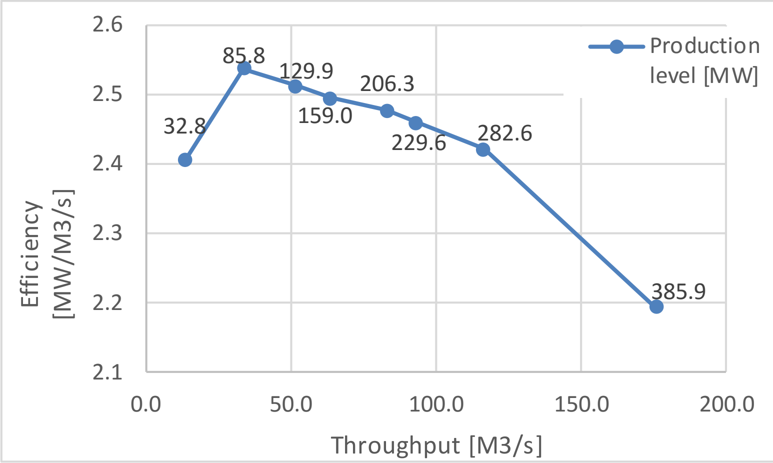

Figure 36 – Efficiency curve for Holen power station, Scenario A.

On a graph such as Figure 35, inter-weekly pumping would have come up as totally chaotic: The line would have to cross the X-axis at least two times a week. If the pumping followed a consistent trend, even the mean graph would have crossed onto pumping. Interestingly, production capacity is never fully utilized during the simulation, only pump capacity is fully utilised for a limited amount of time. In effect, the observed limited extent of inter-weekly pumping supports the idea that longer-term pumping is dominating.

6.4 Scenario B – Big storage

As in Scenario A, the "Big storage" scenario introduces some changes to the data set. Hence, EMPS calibration validity is re-checked. Once more, magazine handling results seem realistic and reasonable; and the trend that magazine levels are kept slightly higher is continued. This is as expected, as the system's energy balance is further improved, and is acceptable in terms of calibration validity – the calibration is kept as is. EMPS percentile plots per waterway can be studied in Appendix A (Figure 78 through Figure 80).

Recapitulating the particulars of Scenario B, as detailed in Section 5.6, the main points of interest are as follows:

i. Energy balance is improved; load is kept as in Scenario A, while wind power in "Norway" is increased to 900 GWh per year, up from 442 GWh in Scenario A.
ii. Pumped hydro capacity and hydro production capacity is increased by 500 MW and 400 MW compared to the Base case, up from 360 and 180 in Scenario A, respectively.
iii. Maximum modelled transfer capacity is increased from 90 MW (Scenario A) to 135 MW for both UK and German transfer series.

Seeing as Scenario B does not introduce anything fundamentally new, expected results in Scenario B would largely be a continuation of the changes from Base case to Scenario A. Extrapolating the results from the previous two cases, this means that ProdMarket is expected to show even lower economic results due to even larger amounts of rationing and buying of interruptible loads. By the same logic, the opposite trend would be true for EMPS: The improved energy balance should continue improving economic results. As it turns out, only one of these inferences hold true: Both EMPS's and ProdMarket's results have improved from Scenario A. It seems that ProdMarket, too, has managed to take advantage of some of the improved energy balance the wind power provides, although, as we shall see, not as effectively as EMPS.

The fact that both models has managed to improve their results, means that the changes introduces to Scenario B are mainly positive. We have already talked about the energy balance in terms of how much of the energy can be delivered using cost-free production. But also (ii) in the above list could have had positive effects, especially in alleviating the possible negative effects of (iii). We remember from the theory section that the short-term balance between load and generation is challenged by intermittent energy resources. We also remember noting that there are costs related to imbalances. In the model, if the hydro system is not able to balance hourly (or rather, price period) variation, it will have to cover the deficit by either buying additional power or by curtailment of load (rationing). This is, in a way, particularly relevant for the interconnectors modelled in this thesis: they do not contribute to improved energy balance (in a normal year), but add considerable volatility in terms of load and production changes. Not only do they increase short-term stress on the hourly power balance, but the yearly changes in energy contribution also means that in some cases, years of net export will overlap with dry inflow years, further increasing seasonal stress. For the modelled system, then, it is plausible that they contribute to increased system costs rather than improved results.

6.4.1 Overall results

Table 22 – Overall results for Scenario B for EMPS and ProdMarket. Mean values. Values are totals over 156 weeks. [31]

		EMPS					ProdMarket
	Unit	Numedal	TEV	Otra	Term	**Total**	
Inflow	GWh	9412.5	7388.1	11113.3		27913.9	28473.7
Spillage and bypass	GWh	610.1	721.9	687.5		2019.5	1555.5
Pumping, use	GWh			399.0		399.0	850.6
Pumping, gain	GWh			596.6		596.6	1097.1
Pumping, net	GWh			197.6		197.6	246.5
Start magazine, sum	GWh	1070.8	1125.0	2003.9		4199.7	4199.7
End magazine, sum	GWh	979.9	1166.3	2366.9		4513.1	4661.2
Contracted power demand	GWh	8985.0	6547.5	9900.0	1230.0	26662.5	26662.6
Delivered hydropower	GWh	8893.3	6624.9	10260.3		25778.5	26703.2
Contracted power not deliv.	GWh	0.0	0.0	0.0	0.0	0.0	22.5
Interruptible load bought	GWh	84.3	0.0	87.7	241.7	413.7	1080.1
Interruptible load sold	GWh	1546.4	30.0	622.9	30.0	2229.3	1168.4
Wind power, Norway	GWh				2700.0	2700.0	2700.0
UK wind and GE PV, net	GWh				-0.5	-0.5	-0.5
Contracted power not deliv.	MNOK	0.0	0.0	0.0	0.0	0.0	-24.6
Net interruptible load	MNOK	28.7	7.4	47.7	-29.0	54.8	-95.3
Net income*	MNOK	90.9	3.7	142.3	-182.3	54.6	-119.9
Magazine level changes	MNOK	-9.2	0.6	23.9		15.3	37.1
Net income, magazine adj.*	MNOK	81.7	4.4	166.1	-182.3	69.9	-82.8

Table 22 (above) shows that EMPS now operates the system at a surplus: 69.9 MNOK adjusted net income. ProdMarket, although improving its results, is spending 82.5 MNOK in adjusted net *costs*. This means that for Scenario B, EMPS beats ProdMarket by $69.9 + 82.8 = 152.7$ MNOK, as compared to roughly 108 MNOK in Scenario A. Once more we will take a look at what factors are at play in getting these differing results.

On the positive side of things, ProdMarket has improved its results. Recorded inflow is slightly increased, spillage is down a little, by around 40 GWh, and interruptible load balance is improved. Delivered hydropower is up by over 500 GWh, while end magazine is down only 82 GWh from Scenario A. In economic terms, reductions in the costs of contracted power not delivered and interruptible loads lower net operational incomes significantly. 24.6 MNOK for not delivered power is 6.3 MNOK down from Scenario A, and a net deficit in interruptible

[31] The * in the final row refers to a correction made to the EMPS numbers: Wind power income has been subtracted to maintain comparability to ProdMarket. For Scenario B, this constituted 223.6 MNOK.

loads of 95 MNOK is an improvement over Scenario A of almost 61 MNOK. This gives operational costs of 120 MNOK and magazine adjusted net income of -82.8, up 52.5 MNOK form Scenario A. Moreover, ProdMarket shows a moderate increase in pump use, now using over 850 GWh over the three-year period, up from just over 700 GWh.

The problem is that EMPS is just so much better than ProdMarket at all things cost-related. For this scenario, EMPS is able to sell $2229.3 - 413.7 = 1815.6$ GWh, totalling a net income from interruptible loads of 54.8 MNOK. This is also the main contributor to the net adjusted income of 69.9 MNOK.

6.4.2 Magazine handling

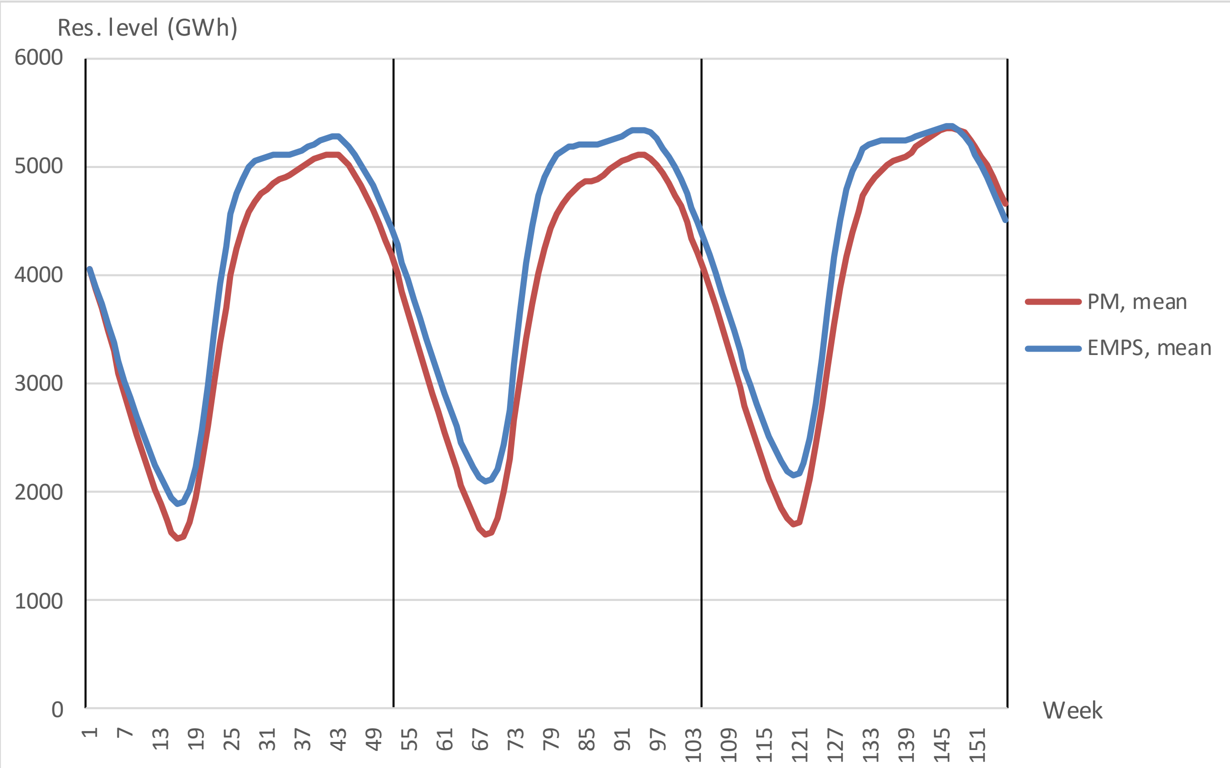

Figure 37 - Scenario B sum reservoir level, mean. EMPS and ProdRisk. [32]

Figure 37 is the Scenario B sum reservoir level plot for both our models. This time, the differences between the models are more apparent: EMPS's magazine level is now significantly higher than ProdMarket's for most of the simulation period. The exception is the last few months of simulation, where ProdMarket once again boosts magazine levels compared to previous years. This time, however, the end level is not that different from EMPS's.

[32] EMPS sum reservoir level is calculated as the sum of the sum reservoirs in each of the three waterways.

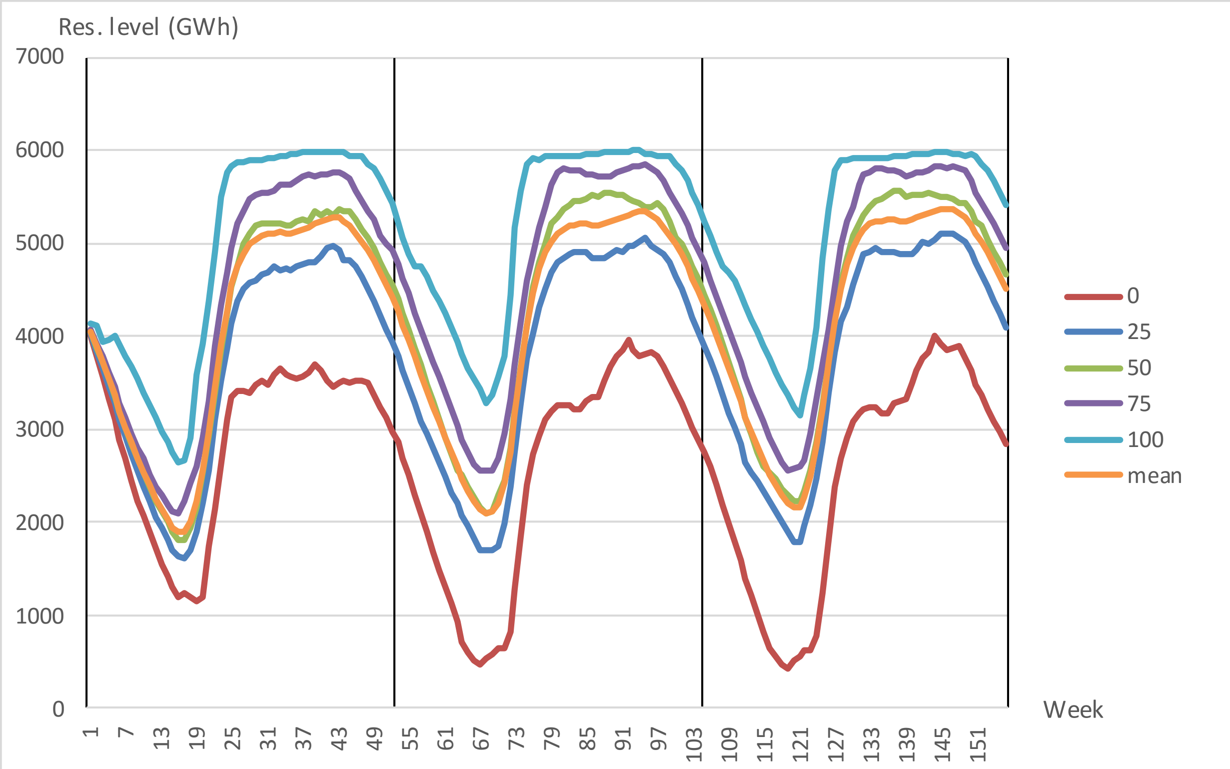

Figure 38 - Sum reservoir level, Scenario A, EMPS. Percentiles.

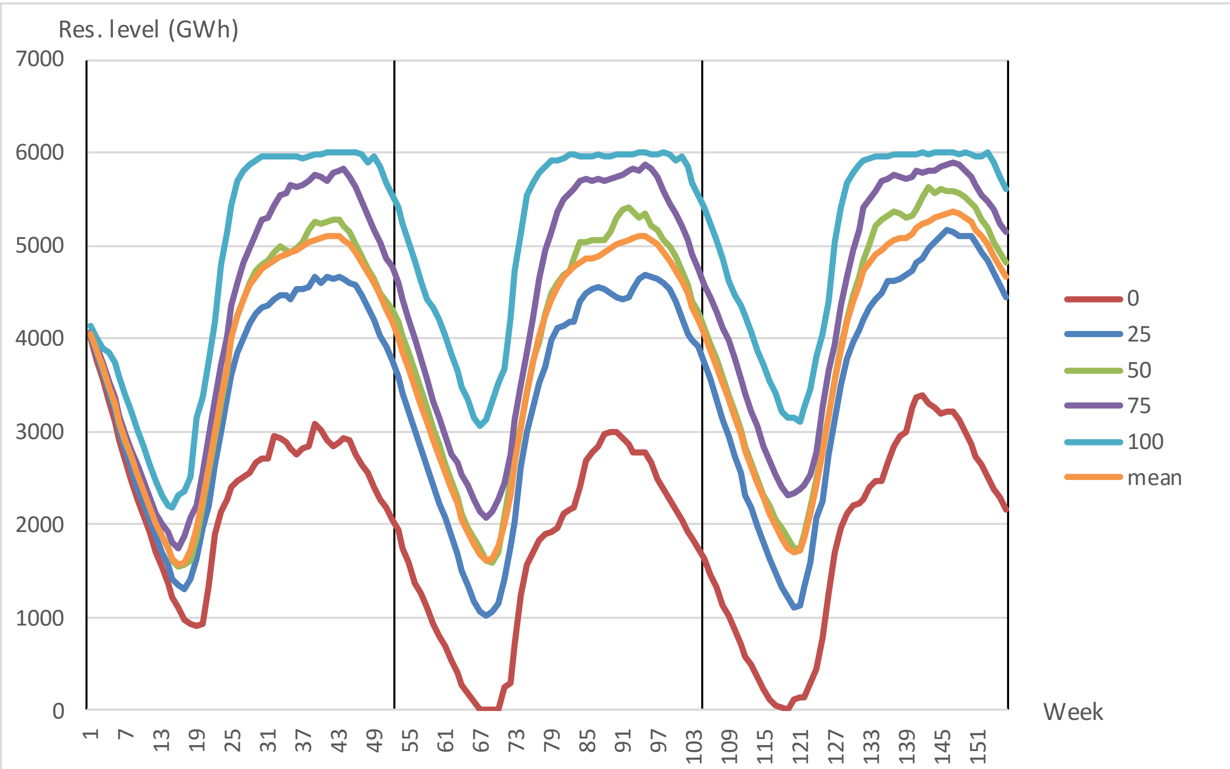

Figure 39 - Sum reservoir level, Scenario A, ProdMarket. Percentiles.

Moving on to the two magazine percentile plots in Figure 38 and Figure 39, there are in this case some notable differences. Once again the most obvious one is the 0-percentile line. None of the inflow scenarios simulated in EMPS comes even close to completely emptying the reservoirs, whereas ProdMarket's "worst case" line shows that at least one scenario leads to several weeks of rationing. The distance from ProdMarket's 0-percentile to its 25-percentile is also larger than for EMPS. All in all, though, the sum magazine plots do not openly reveal any large-scale miscalculations on ProdMarket's side – ProdMarket just runs its system a little harder than EMPS.

6.4.3 Power price

Turning our focus towards price levels, the power price plot in Figure 40 below clearly shows that ProdMarket has a higher price level than EMPS. Analysing the numbers also tell the same story: ProdMarket's average is 12.4 øre/kWh, while EMPS's is as low as 8.6 øre/kWh. Apart from that, the shape of the curves is similar to that of Scenario A, although ProdMarket's winter peaks are not as high this time.

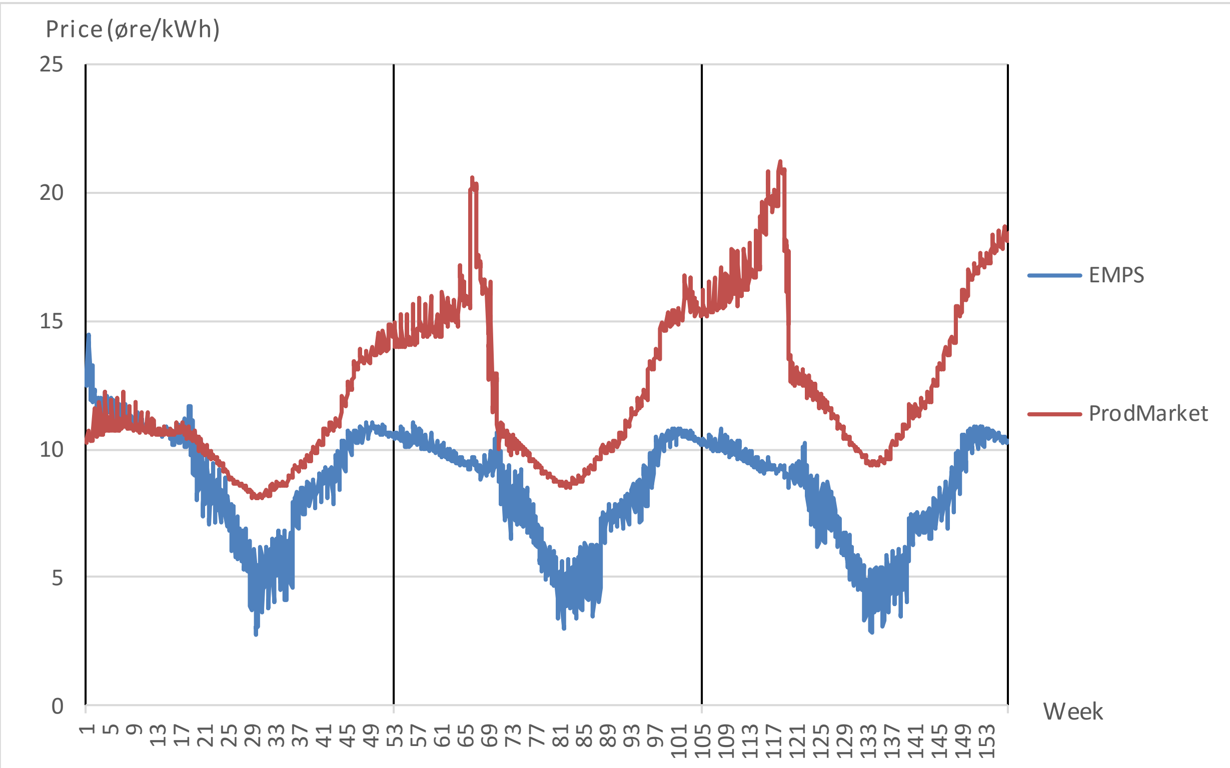

Figure 40 - Scenario B power price, mean. EMPS and ProdRisk. [33]

[33] EMPS power price is from the "TERM" area. Differences between areas were checked and found negligible (less than 0.01 øre/kWh).

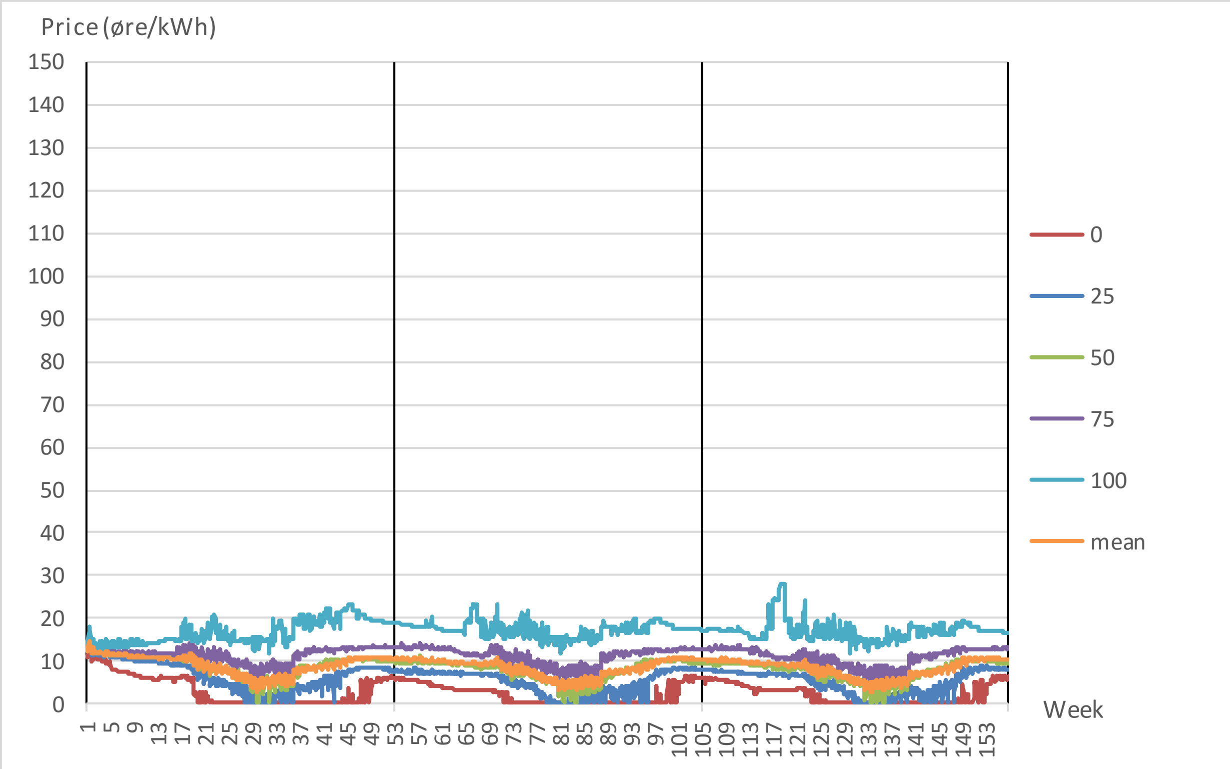

Figure 41 – Scenario A power price, EMPS. Percentiles. [34]

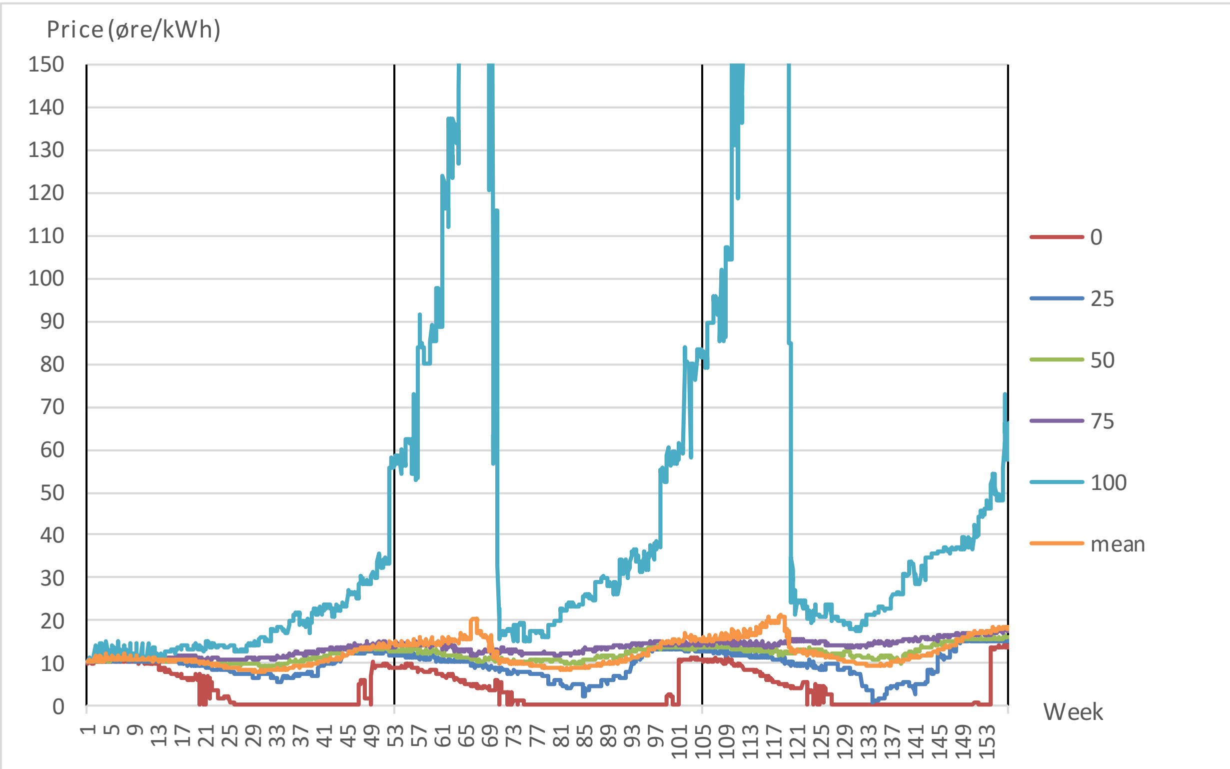

Figure 42 – Scenario A power price, ProdMarket. Percentiles. [35]

[34] EMPS power price is from the "TERM" area. Differences between areas were checked and found negligible.
[35] Price axis cut at 150, highest values reach 450 øre/kWh.

The fact that EMPS never comes close to rationing water is also evident from the price percentile plots, Figure 41 and Figure 42. EMPS never has to turn to extreme measures in order to supply load, hence prices seldom rise above 20 øre/kWh. For ProdMarket, although it too has decreased the duration of its peak periods slightly from Scenario A, there are for most of the period one or more prices well above the same 20 øre/kWh. Once again, the impact of these extremes on the mean price curve is evident: It raises well above the main bulk of scenarios confined in the narrow band between the 25- and 75-percentile.

6.4.4 Pumping

Short-term price fluctuations

As an intuitive way of visualizing the hourly and daily and pump potential, Figure 43 and Figure 44 are plotted. They show the mean price profile for Scenario B across all price points and across a whole week, respectively.

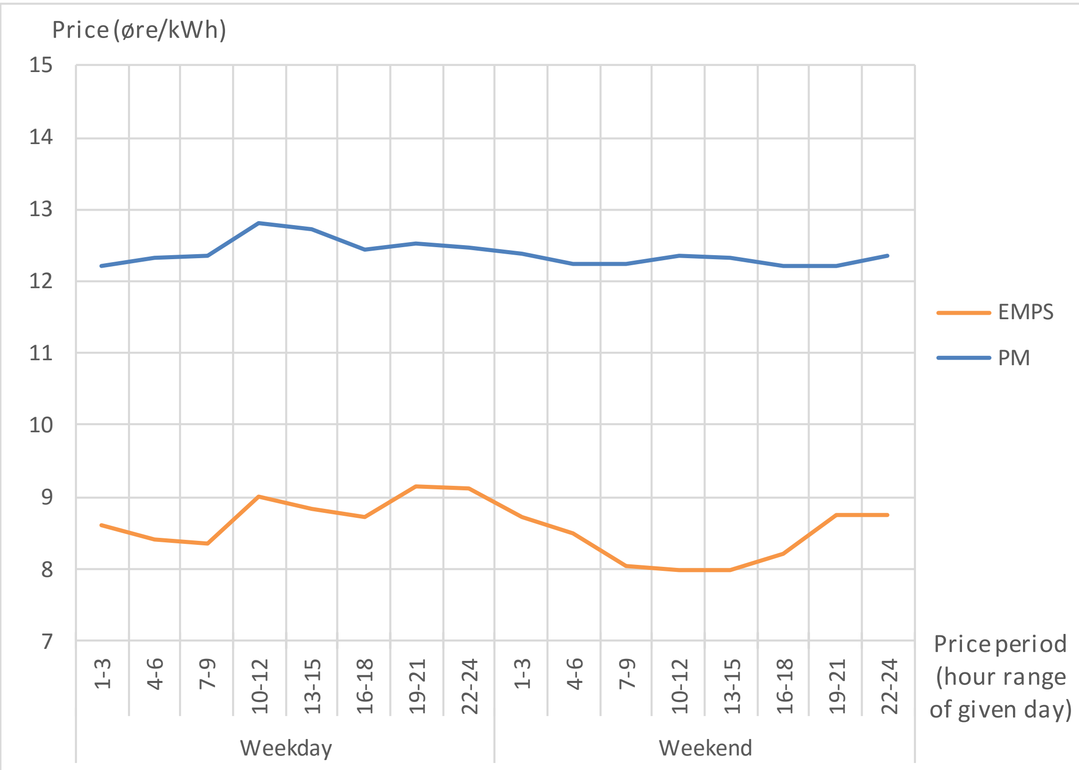

Figure 43 - Mean price profile, all price periods. EMPS and ProdMarket. Scenario B.

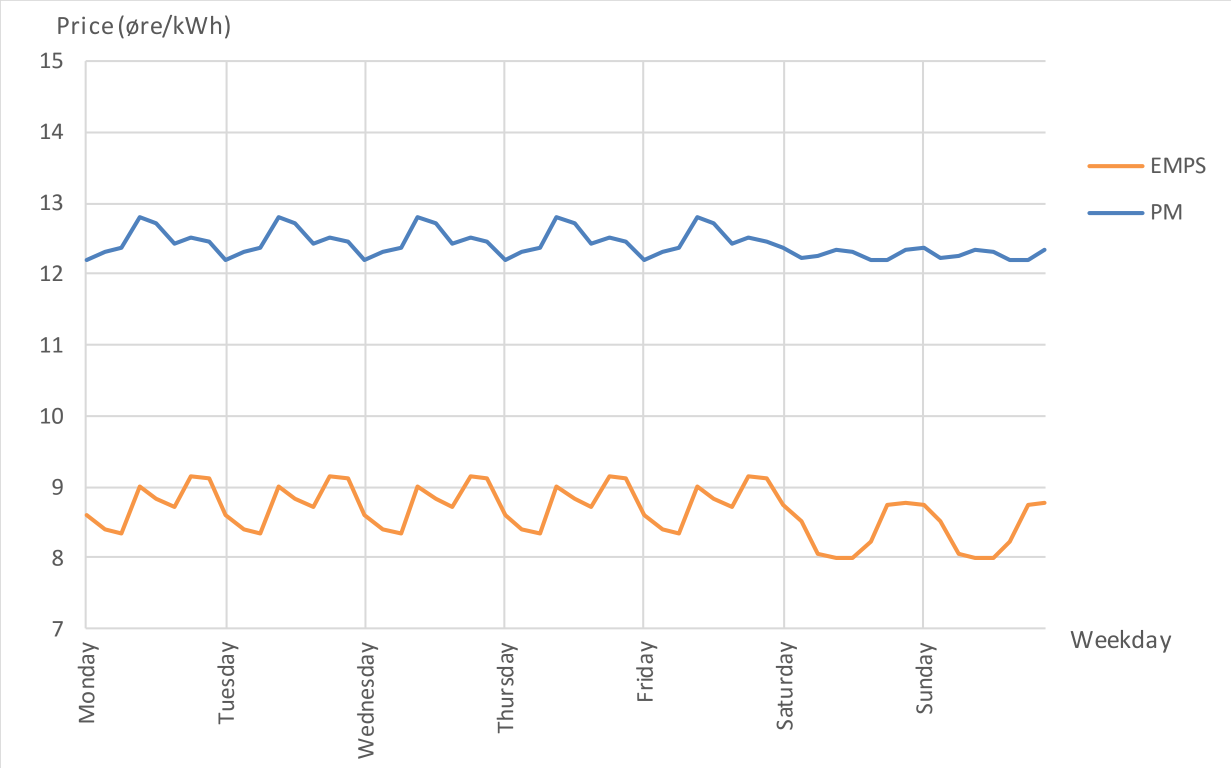

Figure 44 – Weekly price profile. EMPS and ProdMarket. Scenario B.

The price-axis of these figures are the same as those in the previous sections; it is clear that price variations have not gotten any larger. ProdMarket's price fluctuations on weekdays are no larger than five percent, almost non-existent on weekends. EMPS's fluctuations are roughly 9-10 % during both weekdays and weekends. The EMPS weekend price level is somewhat lower, however, so the maximum weekly price fluctuations are almost 15 %, from 8.0 to 9.15. Still, nowhere near the kind of levels required to allow for regular cycles of inter-weekly pumping. Once again, it is somewhat curios to observe that the increased levels of intermittent energy has not led to increased short-term price variations.

As for the two previous cases, results from single inflow scenarios and single weeks were sampled to possibly reveal variations hidden by the mean weekly profile. Once again, price variations generally seam small, in coherence with the mean. Further studies of single scenarios is commented as a possible field of future work in Section 7.1.

Reversible pump usage

Although inter-weekly price fluctuations show limited to no potential for consistent patterns of pumping, there could be considerable potential for weekly, monthly or seasonal pumping. Figure 45 plots mean production over the course of year two from the now $\pm$500 MW reversible turbine installed at the Holen power station. Figure 46 plots the same graph for inflow scenario 1 to exemplify the actual time-variation in single scenarios.

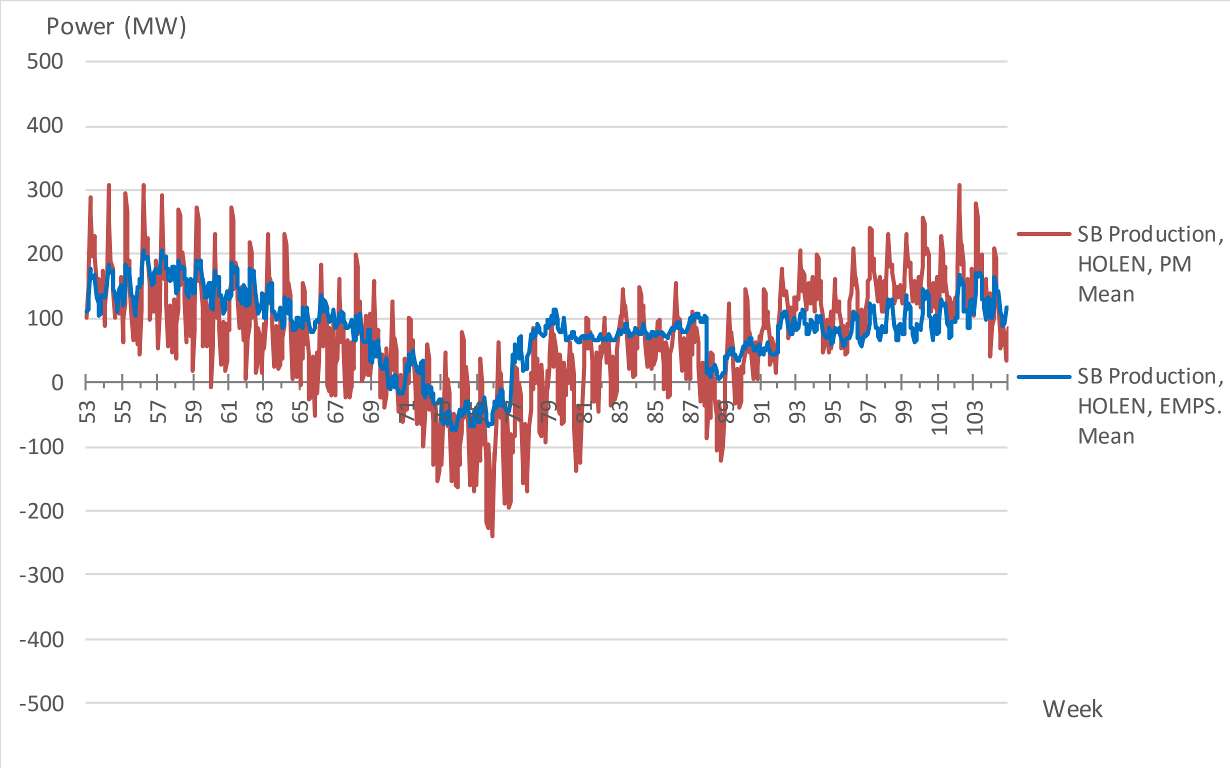

Figure 45 – Mean production and pumping, Holen power station, Scenario B. ProdMarket and EMPS. Negative numbers are power used for pumping.

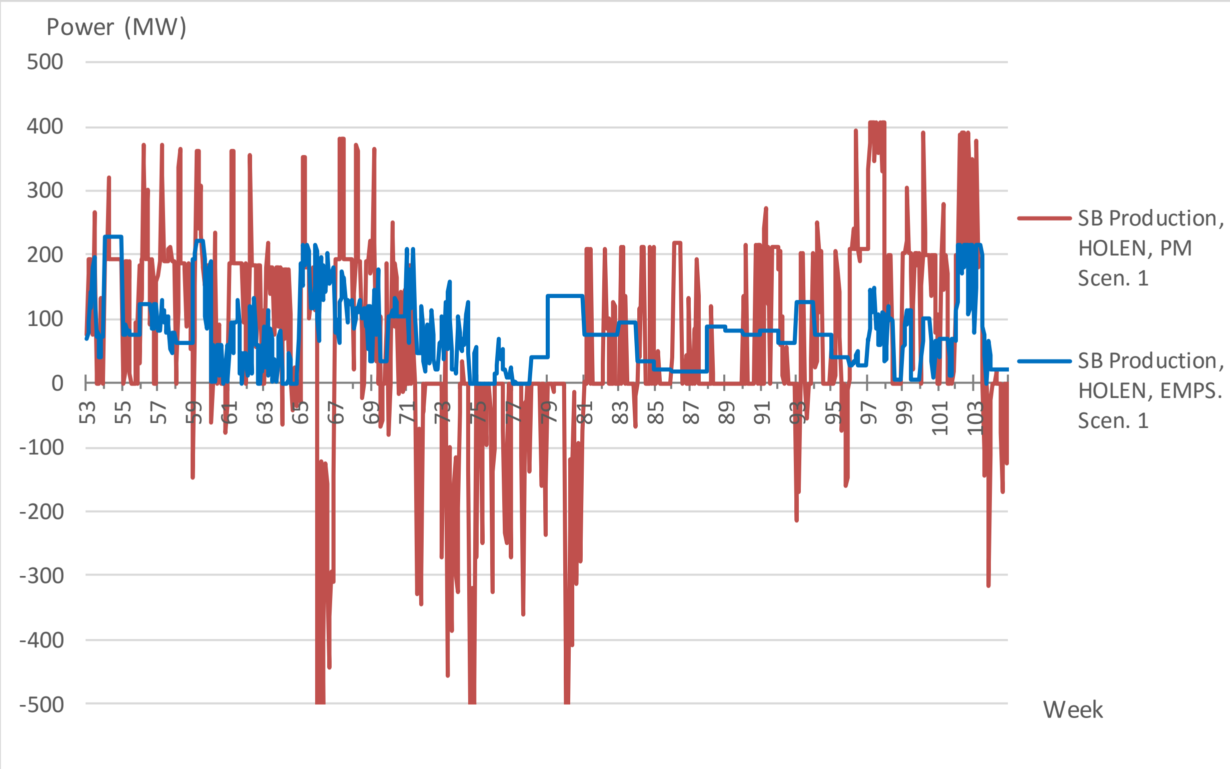

Figure 46 – Inflow scenario 1 production and pumping, Holen power station, Scenario B. ProdMarket and EMPS. Negative numbers are power used for pumping.

At first glance, the two figures look very similar to those from Scenario A: The mean curves follow a similar pattern, so do the single scenario plot. As for the previous case simulation, the main difference between the models, in both plots, is that ProdMarket has larger weekly and inter-weekly variations in production. Again, this could be one reason why ProdMarket also has lower price variations in the short term – the "micro-managing" capabilities of ProdMarket allows it to balance load and generation more effectively. Curiously, EMPS does not find use for the pump at all in the inflow scenario plotted here. ProdMarket, on the other hand, utilizes the full pump capacity of 500 MW for several periods. The full extent of the production capacity is not utilized, however: Same as in Scenario A, there are seem to be a couple of recurring levels of production. The levels are not the same, though, but seem roughly scaled with the increase in production capacity. It is unclear what causes this; refer to Section 6.3.4 for a discussion of possible causes.

6.5 Final analysis: Result comparison

This section constitutes a final comparison of the cases and the two programs EMPS and ProdMarket. As was stated in Chapter 1, the main objective of this thesis has been to study ProdMarket. In that respect, both EMPS and the entire scenario analysis are just tools to achieve this objective. Nonetheless, the performance of EMPS and any real-life understanding gained from the scenario analysis has been commented on as well.

This section attempts so tie together some of the loose ends from the previous subsections, expanding on the results where applicable. First up, the separate case results are brought together to further explore any notable trends in the results. Many of the same aspects that have been covered in the previous sections are commented on. Then, a few key aspects or challenges identified requiring further analysis will be discussed.

6.5.1 Overall results; economy

The economic results of all three cases, and across both models, is neatly summed up in Figure 47 below. It shows the overall net income for each simulation run.

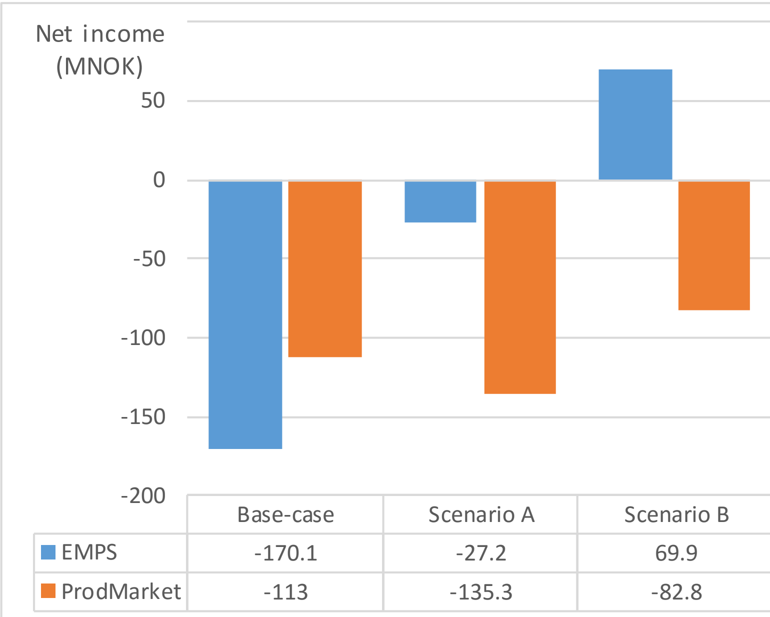

Figure 47 - Net income, adjusted for magazine levels. All scenarios. EMPS and ProdMarket. Higher is better.

For ProdMarket, no trend is clear from one case to another: Scenario A has slightly higher costs than the Base case, but then Scenario B shows the lowest costs of all three. For EMPS, there is a clear trend that, for each case, the system's operational costs decreases. Compared, ProdMarket is notably better for the present system case simulation, whereas EMPS massively outperforms ProdMarket on the two future scenario simulations.

To put this into context: A similarly performed scenario analysis on an almost identical data set ended in the following conclusion on ProdMarket's potential:

> *"ProdMarket's role (...) becomes increasingly relevant: it handles pumping in a complex and volatile power system in a way that clearly outperforms Vansimtap".* [36]
> – Kyllingstad (2015, p. 39)

Quite simply, this level of optimism seems no longer warranted – at least until the model is made more robust. The trend that ProdMarket falls through on the future scenario cases is unexpected, and raises the question of what caused ProdMarket to perform so poorly. Answering this will be the main focus in combining and analysing ProdMarket's case results in the following sections. We are not as interested in analysing EMPS in itself, but the EMPS results will be given more weight in commenting on the overall results of the scenario analysis.

6.5.2 Magazine handling

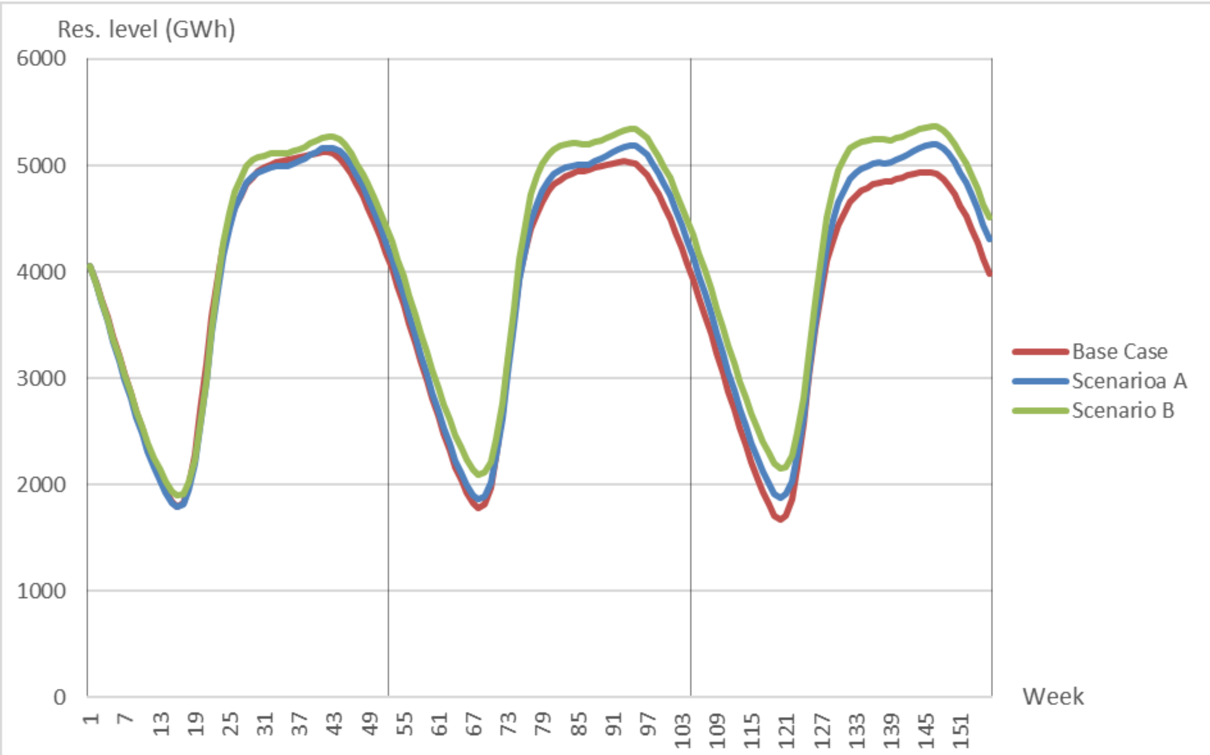

Figure 48 - Sum reservoir level, all scenarios, mean. EMPS. [37]

Figure 48, above, plots power price curves from EMPS for all three simulation cases. As we have already identified, each new case has increased EMPS's simulated sum magazine levels.

[36] Vansimtap is the Norwegian name for EOPS.
[37] EMPS sum reservoir level is calculated as the sum of the sum reservoirs in each of the three waterways.

What is clear from the figure, however, is that the differences between the cases are more and more evident for each simulation year. This highlights something that has been seen in EMPS results: That magazine levels are not as stable across the simulated years as that of ProdMarket – if ProdMarket's last-year peak is not considered, that is. As has been previously mentioned, EMPS seems more affected by start condition than ProdMarket – it takes EMPS a while to reach a "stable" magazine level if the start magazine has been set a little too high or too low. This is of course related to the chosen calibration settings, which indirectly sets EMPS's end magazine level. Scenario A, the most stable scenario for EMPS, seems to have hit a "sweet spot" in terms of start magazine filling and calibration – the amount of water stored each year is seemingly almost identical to the previous simulated year(-s). For the Base case, the start magazine was apparently higher than the "steady-state" condition indicated by the calibration, and so the magazine level decreased a little each year. Lastly, Scenario B, with the largest energy surplus, meant that magazine levels rose a little from one year to another. All this just goes to show that while EMPS is a robust model, it is more prone to flawed user settings than ProdMarket. For a relatively small system such as this, the ability to create the "manual" and "manual 2" calibration settings as opposed to the "automatic" setting chosen by the built-in algorithm, allowed the model to provide relatively good and stable results. In a more complex system, however, where the dynamics of the system are not as evident from the calibration parameters, the need for user input creates an inconsistency that makes it hard to fully trust the model's results without in-depth knowledge or extensive testing. In this respect, ProdMarket aims for a very clear goal of making hydropower support tools more "autonomous", i.e. as unaffected by user input as possible.

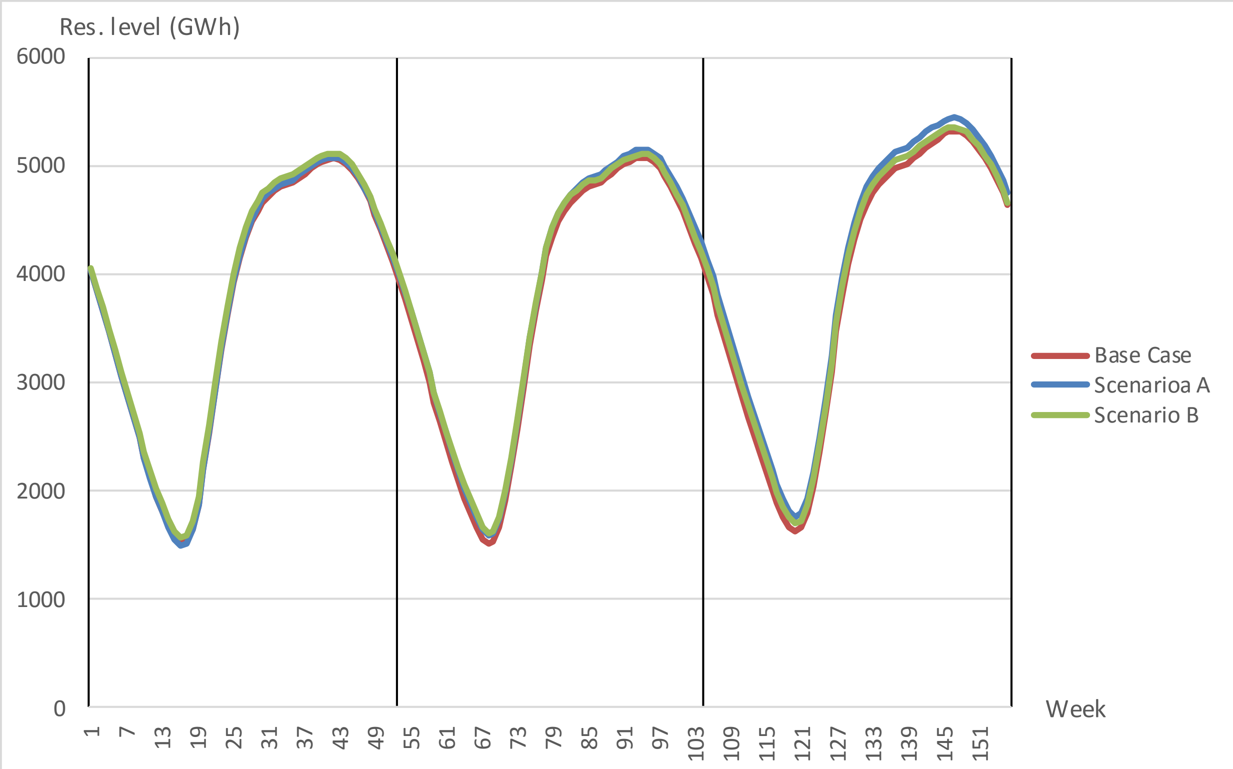

Figure 49 - Sum reservoir level, all scenarios, mean. ProdMarket.

We have, of course, found that ProdMarket has its weaknesses, but on the particular subject of start and end conditions, ProdMarket seems more robust than EMPS. As we know, start values are set using the same general approach in ProdMarket as in EMPS. But where EMPS's end value matrix is set indirectly by calibration, ProdMarket requires no such intervention. This does, of course, put greater responsibility on the model's own algorithm. And as we have seen, ProdMarket's current method for end valuation is not without flaws (which will be further discussed in Section 6.5.5). Nonetheless, where EMPS's calibration affects all three simulation years, although to a varying degree, ProdMarket's end valuation seems to affect mainly the last one to two simulated seasons. In particular, this means that ProdMarket's second year results are not biased by start- or stop-conditions. The above figure, Figure 49, shows mean sum magazine levels for all three simulation cases. Note that first- and second-year levels are almost identical within each simulation run.

So summarize overall magazine handling, there is only one observable weak-point in ProdMarket's results: The water level increase for the third simulation year, presumably due to a sub-optimal end water value matrix from EOPS.

6.5.3 Power price

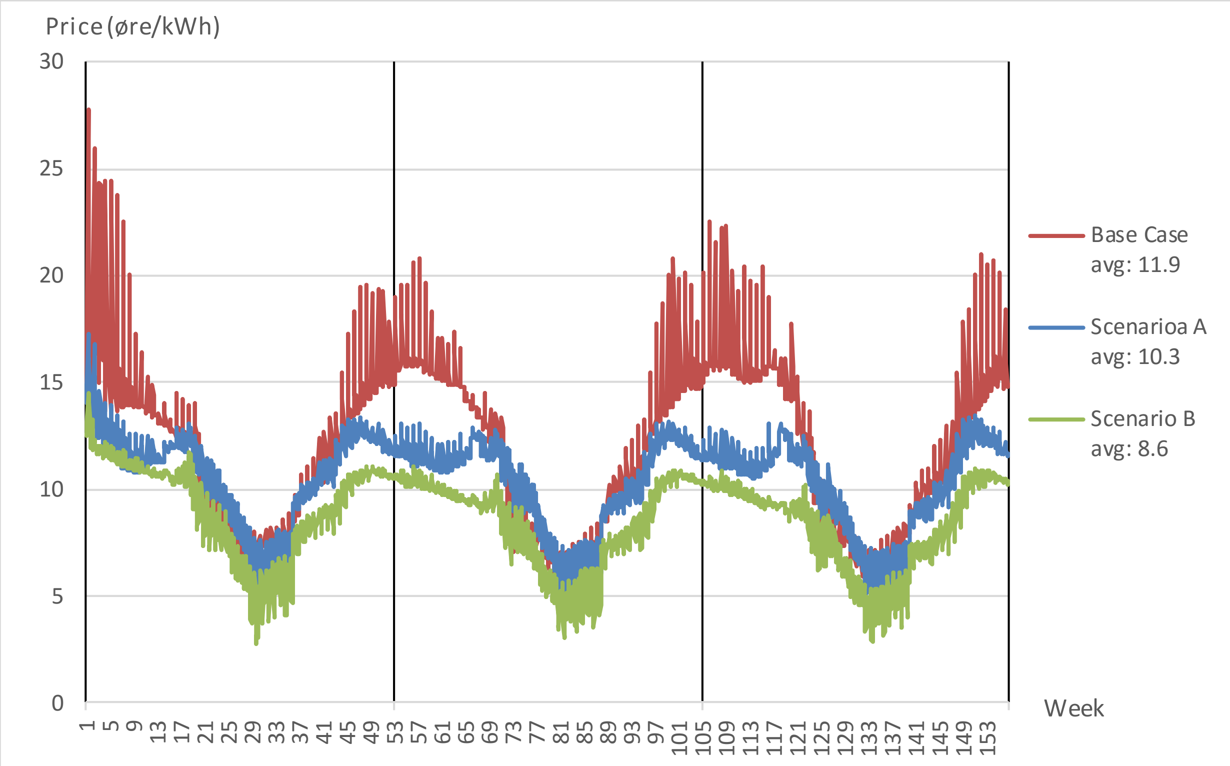

Figure 50 - Power price, all scenarios, mean. EMPS. [38]

Doing the same comparison for price levels, we take a quick look at each model's reaction to each simulation case. Figure 50, above, quickly shows how the changes to each case's data set has affected price levels. The legend also shows average values. EMPS has, as we have seen, managed to take advantage of the improved energy balance in our system as Norwegian wind power has increased its contribution. Largely, winter peaks in power price have simply disappeared, replaced only by a stable, moderate, price level. Each scenario has also seen weekly price fluctuations reduced.

[38] EMPS power price is from "Term" area, not calculated as the average as in BC and SA, as results show near-perfect correlation between areas.

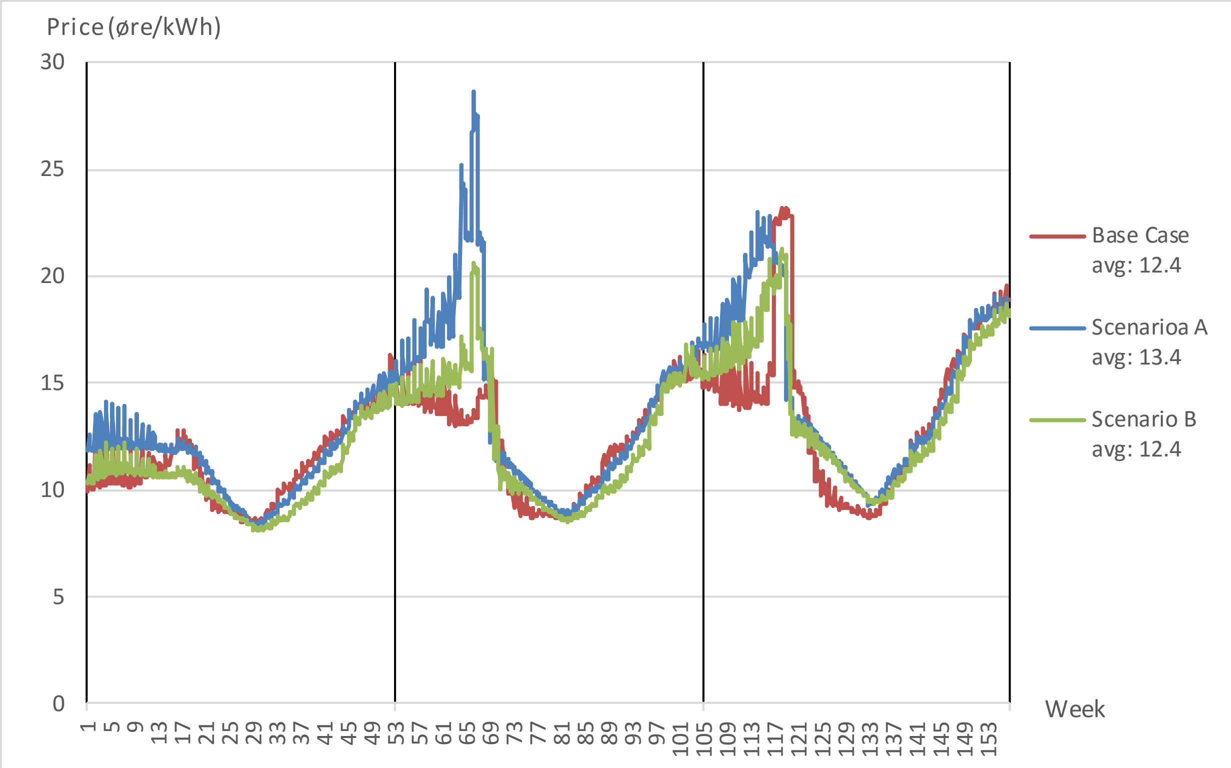

Figure 51 - Power price, all scenarios, mean. ProdMarket.

ProdMarket's plot, in Figure 51 above, do not follow the same trend. Winter price peaks have rocketed for the future scenarios, especially Scenario A. Performed independently, the increased price level could have been dismissed as a result of increased costs due to system volatility – it would have followed dominating predictions regarding future power system dynamics. Compared to the EMPS results, however, there is no good reason why ProdMarket's price levels should increase this drastically for Scenario A. It is noteworthy that Scenario B, which holds, in essence, more of the same as in Scenario A, does not continue the trend in yielding higher prices, but moves average price levels back down to the Base case level.

Summarising, the mean power prices start to reflect ProdMarket's increased operational costs as compared to EMPS. There is no sign, however, as to what underlying causes are at work.

6.5.4 Pumping

Pumping has been a subject of special interest during result presentation and discussion. It has been based on a general interest in this subject in later years: There have been widespread discussions whether current and future European power system trends would lead to increased economic potential for investing in – and operating – reversible pump turbines in Norway. In particular, German and Norwegian politicians and media have discussed whether Norway's massive hydro reservoirs could provide balancing capacity to a new, greener, German power system in the future. The underlying motivation for this interest is the considerable potential for pumped hydro-electric storage in Norway. In this respect, daily or inter-weekly cycles of pumping are especially important: The balancing capacity, in Mega-watts, for a given set of reservoirs, is larger on a shorter time-span. In other words, utilization of both pump and production capacity is higher if the pump cycles are shorter.

Short term price variation

The simulations performed in this thesis used 16 price periods per week – chosen so that they could describe estimated weekly price variations down to a three-hour resolution. This setting was a direct result of the motivation to explore and document any potential for short-term pumping. Based on an assumed round-trip turbine efficiency of 80 %, back-of-the-envelope calculations provided a rule of thumb as follows: Price levels need to drop roughly 25 % from the time of pumping to the time of production, for pumped storage to be worthwhile. Generally, this level is not seen. For the future scenario cases, where a reversible pump is present, average weekly price variations are well below this. Figure 52 plots ProdMarket's weekly price profile for all three simulation cases, Figure 53 does the same for EMPS.

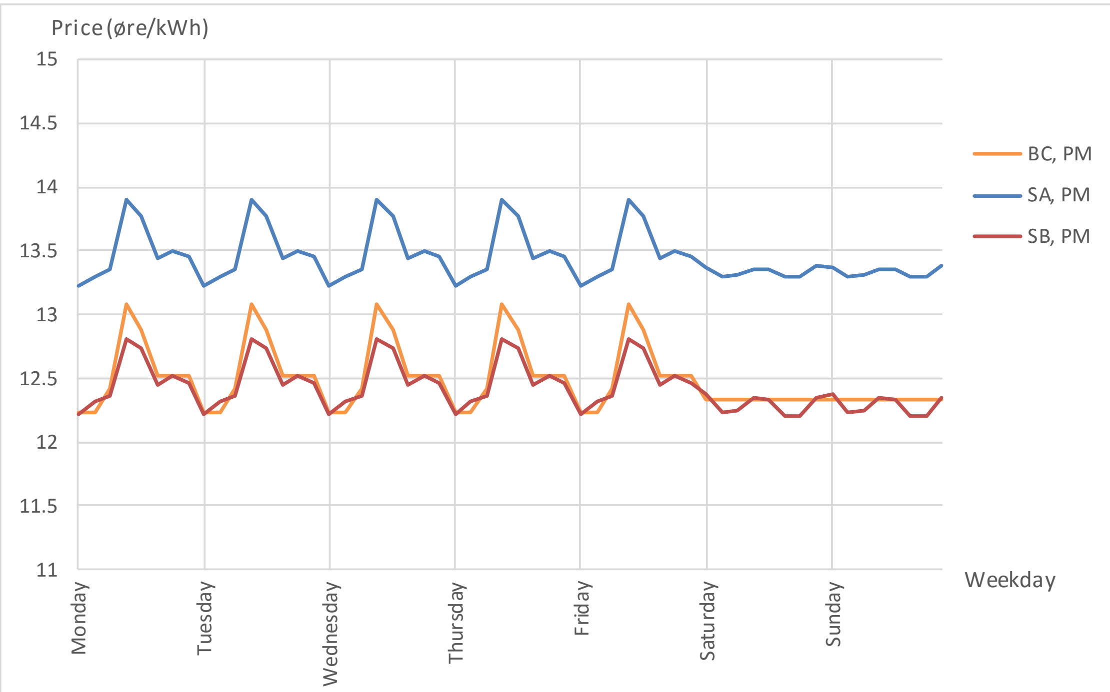

Figure 52 – Weekly price profile. ProdMarket. All simulation cases.

Note the small span on the price-axis of Figure 52: ProdMarket's weekly profile is almost flat. The change from one simulation case to another is generally small in terms of shape, only the level varies significantly. Exactly why ProdMarket has such low variations, compared to EMPS, is unclear. It is likely that ProdMarket is better at evening out price variations due to more detailed water handling and more detailed adjustment in Production levels to compensate for short-term load changes. The use of a price model in the sub-are calculations was also discussed as a possible factor. Could it be that the price model somehow underestimates power price variations going from the overall power market simulation to the local ProdRisk optimisation problems? Yes, it could, but that would not remove them as results were returned to the overall market simulation. By this rationale, the price model could contribute to sub-optimal strategies from the sub-problems, but not to actual reductions in price variations in the market simulation. More on the price model in Section 6.5.6

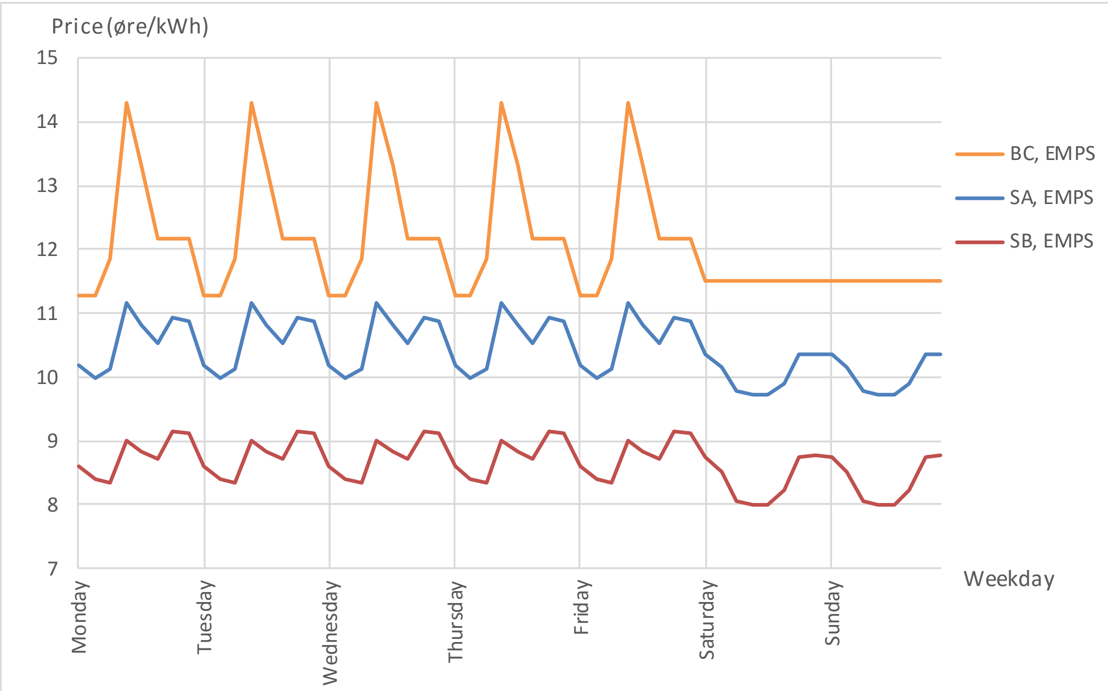

Figure 53 – Weekly price profile. EMPS. All simulation cases.

The EMPS profile has a similar shape to that of ProdMarket, although the scale of the variations is larger (note again the x-axis in the figure). Furthermore, there is a more consistent trend in the results. For each case, the price drop is significant. And for each case, the weekday morning price peak is reduced, while the weekend price drop increases. Both the future scenarios have maximum price variations around 15 % over the course of a week (smaller on a daily basis), whereas the Base case just crossed the rule-of-thumb limit of 25 %.

Due to EMPS's more consistent results, also on the subject of economy, its results is best suited for a more specific comparison amongst the simulation cases. There are some remarks to be made about the general trend of the results – in short, that the new intermittent energy has not increased, but decreased, daily and weekly price variations**.** To comment on how realistic these results are, the first thing to be said is that they are unexpected. It could be that the added energy contribution from the Norwegian wind power increases the Norwegian hydropower system's balancing capacity so much so that it outweighs the added fluctuations from the German and UK interconnectors. Also, it could be that the correlation between the daily load peaks and German PV generation coincides to such an extent that system variability is not increased, but decreased.

Generally, increased penetration of intermittent renewable energy sources is assumed to increase system volatility. This notion should not be accepted as gospel, however: It depends on a complex relationship of production level correlation between each technology and area in a given power system. For low correlation, preferably negative correlation, the variability of a "renewable system" might decrease as compared to a comparable thermal system. There might exist a generation mix "sweet spot" where one technology's production decrease is outweighed by another's increase. For example, imagine how the production decrease from clouds sweeping over an area with large-scale PV production can be compensated for by either increased hydro production due to rainfall from the same clouds, or increased wind production from the winds bringing them in. There are, of course, some factors that complicate this; for example, a storm might bring wind speeds up to such levels that wind power plants are forced to shut down to protect turbines. And cloudy weather does not always bring wind or rain, so it is unlikely that these synergies will completely compensate for the intermittency of new renewable production. Nonetheless, it highlights the need for scenario analysis such as the one performed here. Although not a definitive conclusion, our results do suggest that average daily price variation will not increase with the studied level of renewable penetration.

To sum up, short-term price variations reveal no potential for regular cycles of pumping and production. There could, however, be other short-term fluctuations that are just not as *consistent* as could be hoped for. Wind power, for example, does not present a very clear 24-hour profile, but could nonetheless provide opportunity to pump in surplus periods.

Reversible pump usage

With short-term price variations generally at very low levels – on an average basis – there seems to be limited potential for massive use of reversible pump turbines. The two future scenario cases have, however, seen increased use of the reversible pump in the simulated system. This paragraph sums up the usage trends of the production capacity and pump capacity at the Holen power station.

To recap the scenarios, the installed capacity pump and production capacity of each one is repeated in Table 23:

Table 23 – Pump and production capacity at Holen power station, all simulation cases.

	Unit	Prod. cap.	Pump cap.
Base case	MW	260	0
A – “Small storage”	MW	360	360
B – “Big storage”	MW	500	500

EMPS has consistently had the lowest usage of both the pump and production capacity. Figure 54 plots the second-year usage per price period for all three simulation cases. Remember from when the reversible pump was implemented, in Section 5.5.2, that it was noted how the yearly inflow to the Vatnedal reservoir equalled its storage capacity. This means that this reservoir is crucially important for seasonal storage in the waterway. In EMPS, Figure 54 shows the Base case had some production all year round, but with peaks during late winter and spring – just before the snow melt. In Scenario A and B, this trend was magnified: Summer now saw pumping from the smaller downstream reservoir Bossvatn to reduce spillage there, while production was increased all-year round. Spring production is actually lower in Scenario A and B, presumably due to lower needs for seasonal storage as that the system had more wind power available all year round. Summing up, the pumping observed is traditional, seasonal, pumping – it is done with the aim of reducing spillage, not weekly or monthly pumping or “random” balancing to compensate for price volatility.

There is some weekly variation in production levels during winter, thought to be a response to varying prices (as a result of varying load and intermittent generation), but the (mean) extent is limited. Summing up, EMPS operates the combined pump and production plant in a very traditional way. It is generally not used for weekly up/down-regulation, but follows a set trend based on EMPS’s overall strategy. The real-world system which the data set is based on, is scaled to fit reasonably well with this yearly profile – meaning that the added capacity in Scenario A and B is generally unnecessary.

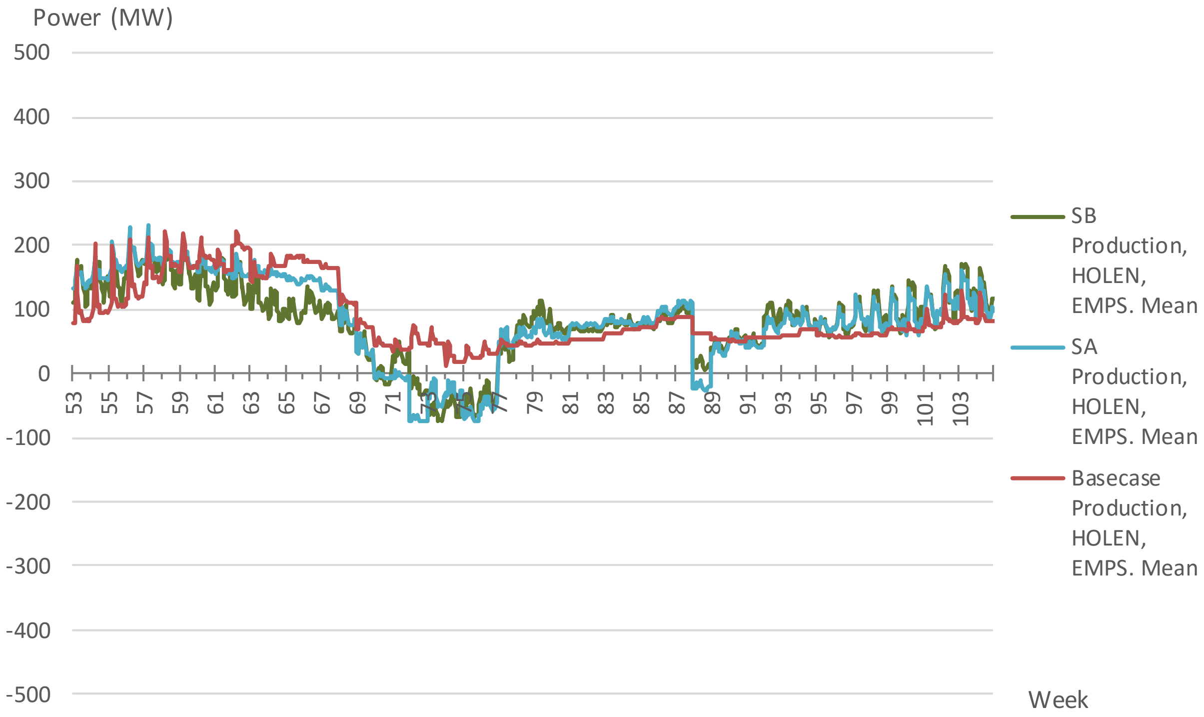

Figure 54 - Mean production and pumping, Holen power station, all simulation cases. EMPS. Negative numbers are power used for pumping.

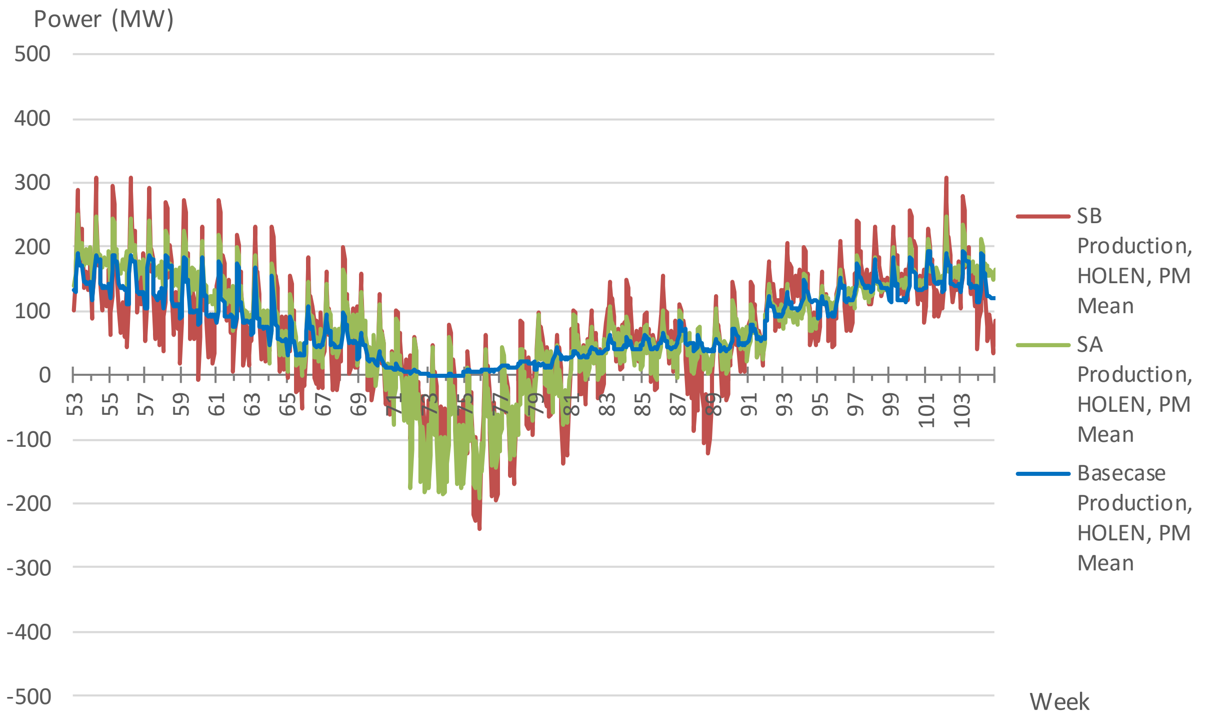

Figure 55 - Mean production and pumping, Holen power station, all simulation cases. ProdMarket. Negative numbers are power used for pumping.

ProdMarket does not completely revolutionise the way the reversible pump is operated, but there are considerable changes compared to EMPS. There are no observable trend of day/night or inter-weekly pumping. But what *is* present, where daily pumping is not, is daily production oscillations. This means that, even though it is not economical to pump during low-price periods, increased production capacity is used to focus even more production to high-price hours. This form of balancing is observed to a much larger extent than for EMPS. Interestingly, studying Figure 55 above, the trend increases significantly from each case simulation to the next.

It seems likely that price oscillations in the system does not warrant short-term pumping simply because there is so much spare flexibility in the existing production system. And ProdMarket seems able to utilize this flexibility to a much larger extent than EMPS – this could be the main reason why ProdMarket's short-term price fluctuations are lower than EMPS's. In this respect, ProdMarket could prove important in re-investment analysis for upgrading of older production equipment. Expanding on these conclusions, they could point toward a more soberly discussion on Norwegian balancing. Large-scale PHES seem to be not relevant for as long as the existing system, with some production capacity upgrades, are capable of handling volatility.

An important in factor in using the hydropower system for balancing, whether by adjusting production or by pumping water, is the availability of that balancing. Only if a reservoir is not emptied due to strained seasonal storage capacity, can the flexibility be conserved for when it is needed. As such, it could be critically important that our future scenario simulations have seen improved energy balances. More than just the value of the energy itself, there is a considerable value in relieving the available hydropower production capacity from some of its seasonal storage stress and allowing the capacity to be used for balancing. For Norway's part, this is an argument towards continuing development of renewable power production even as the system is headed towards an energy surplus. Similarly, for Europe, it is an argument towards establishing technical, political and financial tools that shift the focus of Norway's hydropower system away from storage and towards balancing.

Comment on pump income

Valuating pump income directly is somewhat tricky, since production falls at a later stage than the pumping itself. Pumping in itself is a loss in the present, and is based solely on an expectation that future income may increase. For complex patterns of pumping and production, it is hard to "decide" at what point each unit of pumped water should be considered produced. The simplest way around this problem is to use a hydro-planning model's own water values at the time of pumping. This is, in essence, just what is needed to value the pumped water: A description of expected future income. The water value of the reservoir where water is pumped from can be compared to the water value in the receiving reservoir for an instant valuation of pumping water. This is, in essence, what both our models try to do: EMP's algorithm compares so-called relative water values – rule-based estimates of the true water value – and ProdMarket optimizes pumping based on future value functions estimated by cuts (sections 4.1 and 4.3, respectively). It is obvious from this that each model's approach is only as good as the accuracy of its water values – and although ProdMarket has shown points of weakness in terms of overall economic results, the SDDP approach (at least theoretically) opens for more accurate individual water valuation by accounting for every single reservoir in its optimizations.

Extracting the income of a modelled reversible pump station based on simulation results from EMPS or ProdMarket is not possible using current result extracting modules (such as the ET-module). This makes it hard to perform investment analyses et cetera. Currently, the way around this is to run and compare two separate data sets, identical down to every detail except that one contains a pump. The overall results will then estimate the system impact of the pump. Due to calculation times, however, this is not a straightforward task, especially if several alternative capacities are to be compared (as would be highly relevant in an investment perspective). The ability of EMPS to quickly run through several sets of alternative data sets and compare them, is one of the model's strengths.

There is also a possible drawback of using system costs as indicators of pump profitability: The owner of the pump may not be the same as that of the system. This means that even if the overall socioeconomic benefits of pumping are large enough that they justify investing in a pump station, it may not be economically feasible for the prospective pump owner. Of course, the pump owner earns a surplus operating income if price fluctuations are high enough that subsequent production covers his extra spending on electric power to the pump, but this income alone may not be enough to reflect the system-wide benefits of running his pump. This problem is another aspect of what was mentioned in the background chapter when discussing balancing power (section 2.2.4), namely making sure that updated financial tools allow monetising of new system services. If, say, a massive surge of intermittent renewable generation enters the system, then, within the hourly resolution of the market clearing, the prices will reflect this by dropping. If the surge is unaccounted for during the day-ahead planning from the day before, which it may very well be due to the nature of such variations, there will also be a reward to collect in the intra-day balancing market for reducing scheduled production. The intra-day market is hence one example of a financial tool that supports system balance by compensating producers.

6.5.5 End valuation of water

This section discusses a topic that has been mentioned throughout this chapter. When first introduced in Section 4.3.3, it was noted that end valuation of water could have either an internal or an external use. Section 4.3.3 focused on internal valuation; that is where this section will start. Subsequently, the external end valuation as performed by the ET-module is discussed. Furthermore, a couple of different methods of quantifying the economic effects of end valuation is explored.

Internal valuation

i. Internal use in the model's optimization algorithm. Provides an end boundary condition for the simulation period.

Summing up the three cases in terms of end valuation of water pretty much boils down to the following: ProdMarket shows high end magazine levels for all simulation cases. Too high end internal valuation of water is considered the likely culprit: Higher end valuation would make it optimal to have as few inflow scenarios as possible with negative magazine level change.

ProdMarket clearly overestimates the end value of water as compared to EMPS, but to a decreasing extent for each case simulation. The end magazine level for the two models are very different for the Base case, whereas the Scenario B level is reasonably close. In practice, ProdMarket's end level has not changed much – it is EMPS's end level that has increased for each simulation. For EMPS's part, this is due to the same calibration setting being used for changing data sets. Each case has improved water balance and decreased power prices. The end valuation, which is indirectly affected by the calibration, has hence become less accurate for Scenario B. For Scenario A, the start condition and calibration setup, although created for the Base case, seemed to have fit together well, keeping magazine levels on similar levels across all three simulated years.

ProdMarket's internal end valuation uses an EOPS module to perform the required end value iteration (Section 4.3.3). In itself, using end values from EOPS should not give results all that different from the EMPS model, but, as it turns out, the particular settings used for this thesis has caused a chain of events that has the combined effect of an exaggerated end valuation. Section 4.3.3 suggested three possible reasons why the end valuation in ProdMarket, as calculated internally by an EOPS module, could be higher than normal:

i. ProdMarket run in “Hot start” due to error in 1toNVV-module”

ii. EOPS does not support wind

iii. PM is generally better than EOPS

Speculating on the importance of each one, the first and second reasons are thought to contribute the most to the elevated end values. The first aspect meant that the initial EOPS valuation was calculated for the default data set, which had 10.58 TWh of firm demand (Section 5.1), whereas the updated Base case data set had removed a full 1.75 TWh of yearly load obligations (Section 5.3). The second factor, EOPS’s inability to incorporate wind, is likely to have had an increasing effect for each simulation case, as the wind energy added constituted an increasing improvement in the systems energy balance. The first and second factors both pull in the same direction; The combined effect is likely magnified. The third suggestion, that PM being better than EOPS should increase end valuation, is thought to have somewhat smaller effects. Differences between ProdMarket and EOPS are generally not thought to be sufficiently large that this would be a major factor.

Based on ProdMarket’s stable end magazine level throughout all three simulation cases (refer to Figure 49 in Section 6.5.2), the error in the internal end valuation is assumed to have been stable. The economic ramifications of these factors causing flawed end valuation is unknown. To even begin to estimate them, the external end valuation has to be considered.

External valuation

ii. External result analysis. Provides a means of adjusting economic results for changes in magazine levels.

Moving on to the second use of end values (ii), i.e. calculation of economic results, the end valuation should generally try to cover two objectives. First, it should be a realistic approximation of real system costs. Secondly, the valuation should form a reasonably fair basis for comparison between models. The second objective is most important in our case, as the absolute value of the economic results are of little use to us.

External end valuation is not necessarily about valuing the entire quantity of water left at the end of the simulation period. Typically, the approach is to value the *change* in water quantity from the start of the simulation period to the end. Thence, if a model ends the simulation with the same amount (and distribution) of water as the start, there is no need to value the water. Similarly, if two different models end their simulation at identical reservoir levels, the objective of creating a fair valuation is instantly fulfilled. But, this may or may not be true only for the mean magazine level or only for the sum of individual inflow scenario levels. There are different approaches at valuating magazine level change, of which ET supports two. ET's default approach, which will be considered first, forms the basis for the discussion in the following paragraphs.

The result generator used for economic results in this thesis, ET.exe, has two modes for valuing end-of-period magazine levels. The default method, which has been used in this thesis, is based on each models simulated power prices. For each simulated inflow scenario, ET calculates the magazine level changes (per reservoir) and multiplies it with the average power price of that inflow-year; the results for all three years across all inflow scenarios are then added together (Henden, personal communication, 30.05.2016). This means that the external end valuation of water is mostly dependent of the operational costs of the model used. It does, however, mean that a poor solution resulting in higher power prices will also reward or punish changes in magazine levels more than a better model. In our case, where ProdMarket has shown higher average power prices, this means that it will also be rewarded more than EMPS when magazine levels increase, and vice versa when magazine levels decrease. Does not this give ProdMarket a head start in cases where it increases magazine levels throughout the simulation period, as we have seen for all three simulations? Yes, and no. Yes, higher internal power prices will increase reward as calculated by ET. But higher power prices mean the system has been operated more expensively: saving water comes at a cost, even if done "optimally", as it means delivering less water during the simulation period. Moreover, high power prices may be a result of sub-optimal water handling. So any gain in end magazine valuation are presumably consumed by the increased cost during operation. The exact dynamics of total results as opposed to magazine levels and operational results is not known.

Economic contribution

Net contribution from differences in both internal and external end water valuation is very hard to quantify. There are several considerations to be taken; multiple factors pull in different directions. We will, however, try a couple of methods to evaluate how much end valuation of results could have impacted our results. The presumed effects differ somewhat between the cases as well.

The “fairness” of ET’s external valuation would have had decreasing effects from one case to another: For the Base case, where the end magazine gap between the two models was large (EMPS had a negative magazine trend, ProdMarket a positive one), the effects could potentially have been quite large. The fact that ProdMarket nonetheless provided good results for the Base case suggests that external valuation is not decisive for the results. For Scenario A, the distance between the models was slightly smaller, and so end valuation should contribute less to the results. Finally, for Scenario B, end magazine levels were relatively close, both between the models and compared to start magazines, and so differences in how ET values the reservoir change should have smaller implications.

On the other hand, ProdMarket’s internal valuation is thought to have had a stable effect on economic results. Given the internal miscalculations, ProdMarket optimizes based on flawed end magazine valuations. Objectively, as subsequently evaluated by ET, this causes ProdMarket to perform suboptimal decisions resulting in lowered economic results. Graphically, seeing a change in magazine levels from year two to three must inevitably induce a smaller or larger cost increase: Year two constitutes ProdMarket’s own estimate of optimal operation, which the third year then deviates from. Estimating the size of the loss induced is not easy. As the end valuation demonstrably impacts only the last few months of a simulation run to a significant degree, the end value problem is considered unlikely to account for a loss in the range of hundreds of million NOKs – as is the relative change between the two models moving from the Base case to Scenario B. Further studies would be required to ascertain this.

Alternative end valuation: ET

In fact, ET supports two alternative methods for valuating end magazines. The second approach, which has to be manually unlocked by using a password, is to base the end valuation on water values calculated by the models – as done by the models themselves internally. This opens the door to explore the extent of ProdMarket’s “miscalculations” in terms of end valuation.

On their own, ProdMarket’s results for the alternative valuation is not very helpful. But, if the difference between it and EMPS’s results could be calculated, it could be compared to the difference using the default approach. The change would estimate the value of ProdMarket’s miscalculations. Unfortunately, the second mode running ET could not be made to work for EMPS. Hence there is no base for comparison, and this method had to be discarded.

Alternative end valuation: Rerun of Scenario A

A second approach in evaluating the size of the economic loss due to ProdMarket's end valuation was tested. It was inspired by an updated version of 1toNVV that could, with some manual help, be made to update the EOPS water value matrix used in ProdMarket. The idea was as follows:

- Trick EOPS to include wind in calculations – at least the Norwegian wind, so that the energy balance is close to the correct Scenario A level.
    - i.e. add 3*442 GWh of energy.
- Manually run Vansimtap to update end water value matrix.
- Manually running an updated version of 1toNVV that could handle 16 price periods.
- Start ProdMarket from hot start, i.e. one iteration should be sufficient?

Tricking EOPS into including the energy amount of a wind series was done very approximately by creating a power contract that allowed EOPS to "buy" energy at no cost. The contract had a flat capacity profile of 50.59 MW, as this would equal roughly 443 GWh of energy per year. The implementation is shown in the below table.

Table 24 – Implementation of contract mimicking wind in EOPS: Alternative end value, Scenario A.

```
Datagruppe:   Kj/p/Import
Krafttype nr: 280  vind_Norge-term
Brensel:
Virkningsgrad:100.00 %
Effektprofil: PE_Flat
Effektprofilen brukes som en SKALERING for kapasitet
Plassering:   TOTAL
Lokale kostnader:     0.00000 |re/kWh
-----------------------------------------------
Periode : Start : Slutt :  Pris    :  Kapasitet  :
nummer  : -uke  : -uke  :(|re/kWh):   (MW)      :
-----------------------------------------------
     1   :    1  :  156  :   0.00   :    50.5900 :
```

The simulation was stopped after only one outer iteration, using "hot start" from the existing Scenario A simulation. Convergence was poor, but no more iterations were performed due to what was seen from the preliminary results: Quite frankly, the results from the updated WV run were even worse than the original Scenario A simulation run. Clearly, more iterations could have improved results somewhat, but this was considered unnecessary: The updated WV's were apparently more "off" than the default WV's. Economic results were down by over 230 MNOK.

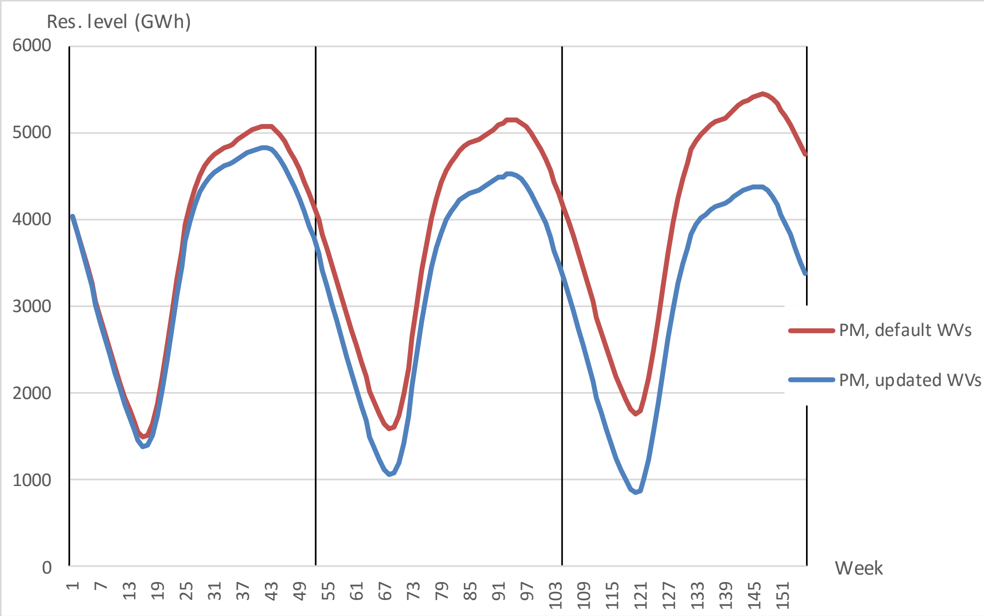

Figure 56 - Mean reservoir level, Scenario A, updated WV matrix. ProdMarket.

Where the default valuation matrix caused an increase in reservoir level mainly for the third year, the updated matrix has major implications for the third year as well as significant effects of the second-year results; this time, the reservoir level drops very low. Clearly, the observation made in Section 6.5.2 that "ProdMarket's end valuation seems to affect mainly the last one to two simulated seasons" is correct only to certain extent.

It seems that the approximate way of "tricking" EOPS into lowering future water values have created an overly optimistic future. In a nutshell: ProdMarket works so hard to get some use out of its water, which is valued as next to "useless" at the end of the simulation period (given the exceedingly optimistic future), that it considers it beneficial even if several of its inflow scenarios show massive amounts of rationing.

In retrospect, the likely reason for the considerable error is as follows: The interruptible load contract provided that was supposed to mimic wind power is much more valuable than the equivalent wind energy as it is not intermittent. EOPS needed not plan for the occasion that the wind stopped blowing: It had full control of when it wanted to "buy" wind energy – a valuable option indeed. Moreover, no method of including the variability of the cross-country interconnectors to Europe was applied. This too will have represented a considerable simplification. The "lesson taught" is as follows: Energy balance is not everything; the negative impacts of production uncertainty due to intermittent power sources constitute such a contribution that water values are obviously flawed when it is not included.

Summing up, no effective method was found in estimating the economic loss in ProdMarket's result due to a flawed end value matrix. This means we can only speculate on what portion of ProdMarket's relative drop in results are due to this subject. Hence, other possible factors have also been considered. Another – equally diffuse – possible factor, is explored in the following last section of the analysis.

6.5.6 Price model

This subsection delves a little deeper into a possible technical explanation of what could have caused ProdMarket to deliver sub-par results as in the two future scenario simulations. The observations made here will subsequently constitute an important part of the "Further work"-section.

As the heading suggests, the price model is considered to be of some importance. Exactly how it affects economic results, and whether it is even a major factor, is not perfectly clear. But the main rationale for suspecting the price model is quite simple:

> *Kyllingstad (2015) showed that ProdMarket performs well on a similar data set with large amounts of intermittent hydro production in one of the (ProdRisk-optimized) waterways. This thesis has shown that moving the intermittent power to the overall system causes poor results. The overall system is simulated by a market simulator which also builds on ProdRisk, so it too should be capable of handling the intermittency. Ergo, the problem lies in how the two modules communicate.*

ProdMarket runs ProdRisk in its area simulations, as well as a ProdRisk-based market simulator on its overall system. Through years of practical use, ProdRisk is known to provide good, stable results (Henden, 2015b, p. 6). Hence, we can be quite confident on how ProdMarket's two main modules are capable of handling the system they are set to simulate. In a nutshell, then, it all boils down to how the information from the market simulator is translated to the local ProdRisk-optimizations; the price model is responsible for this. Refer to Section 4.2 and 4.3 for the explanation on the role of the price model (and price points).

Follow-up interviews with co-supervisor Arild Lote Henden at SINTEF were conducted after simulation results were ready. It was confirmed that internal test results had indicated certain problems with the price model mechanism used in ProdMarket (Henden, personal communication, 01.06.2016). Apparently, a problem has been observed regarding the spread of price scenarios, particularly the extreme cases (Henden, personal communication, 01.06.2016). Specifically, one or a few inflow scenarios could sometimes be observed to be “stuck” at extreme price levels for unnaturally long periods of time, all the while all other scenarios would remain very close to each other (Henden, personal communication, 01.06.2016). Moreover, comparing results between iterations, the effect has been observed to become increasingly evident as more iterations are run (Henden, personal communication, 01.06.2016).

The problem is thought to relate to how the two outermost price points in the price model is calculated, along with their respective transition probabilities (Henden, personal communication, 01.06.2016). Mo et al. (2001) explains how inflow scenarios are grouped into a set of discrete blocks that subsequently forms a price point – a key topic is how the scarcely ‘populated’ outer areas of the result space are treated. The basic problem is that, for the most extreme results, there are very few observations that can be grouped together to create a price point (Mo et al., 2001). Specifically, a low number of observations means that correctly representing the transition probabilities becomes difficult (Mo et al., 2001). Henden (personal communication, 01.06.2016) suggested that once an extreme price point was reached during simulation, the calculated probability of *not* continuing along a scenario of extreme it was sometimes estimated to be small to none. This is considered unrealistic: Although extreme prices in the current period indicates increased probability of increased prices in the next, most real scenarios gradually leave the most extreme spectre of prices within a relatively short amount of time (Henden, personal communication, 01.06.2016). In other words, even the most extreme inflow scenarios have a long-term expected future price of roughly the same as the other inflow scenarios (Henden, personal communication, 01.06.2016).

The question remains, how does this relate to the results presented here? There are currently few concrete answers on this issue, but theories for further studies can be proposed.

First of all, a selection of result plots will be created and analysed for any eventual clues as to whether our simulation results could be affected by the same problem. Moreover, the analysis will attempt to answer whether or not using the “hot start”-feature might have increased the presence of this alleged problem in our results in the later cases. We have noted repeatedly how EMPS increasingly outperformed ProdMarket for each simulation run. It is plausible that continuing simulations from a previous price record could have contributed to a build-up of the possible problems related to the price model? As was proposed in Section 6.1.2: “Presumably, running 10 hot start iterations on three largely identical systems is not that different from running 30 iterations on a single system”.

Base case

In the following, a series of price percentile plots will be analysed. This time, the percentiles are chosen somewhat differently than before: In addition to the 0, 50 and 100 percentiles, the 4 and 96 percentiles are plotted. With 50 inflow scenarios, the fourth and 96th percentile shows the third most extreme scenario in each direction at any given time. ProdMarket's results are of the most importance, but EMPS's will be plotted where relevant for comparison. Figure 57 and Figure 58 shows EMPS and ProdMarket results from the Base case, respectively.

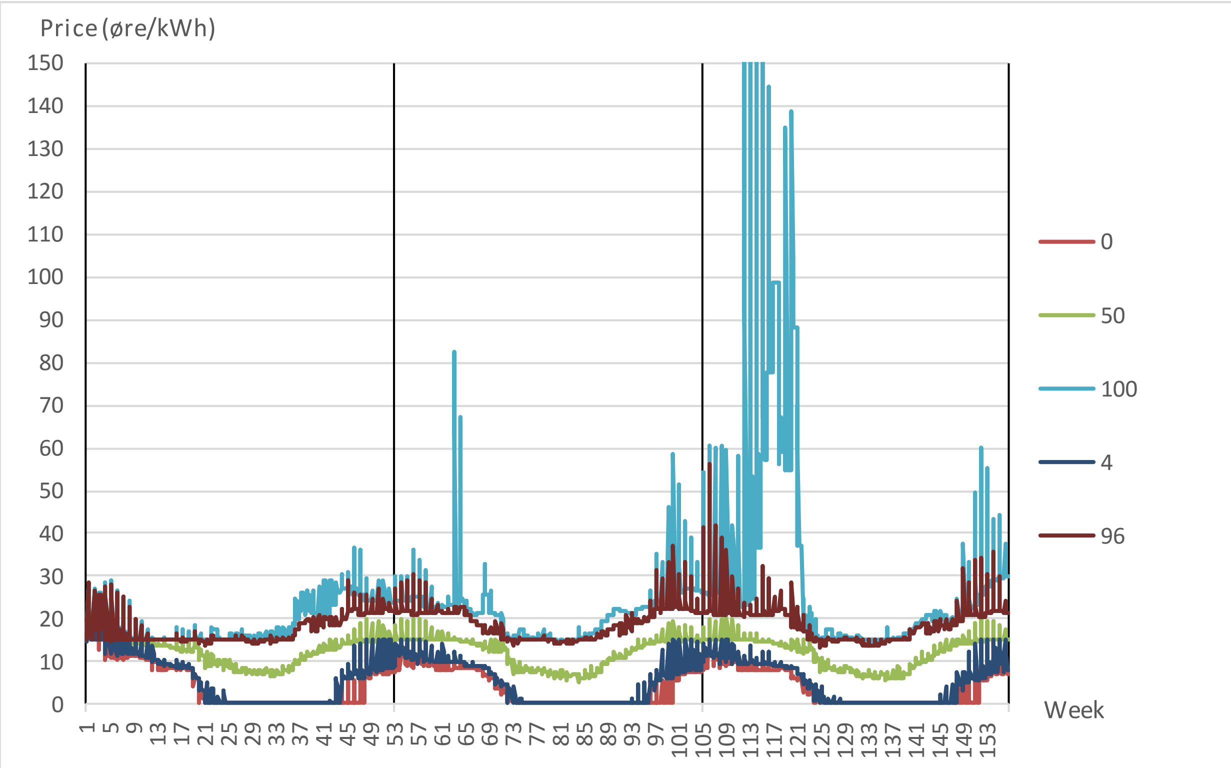

Figure 57 - Base case price, alternative percentile plot, EMPS. [39]

[39] Price axis cut at 150, highest values reach 450 øre/kWh.

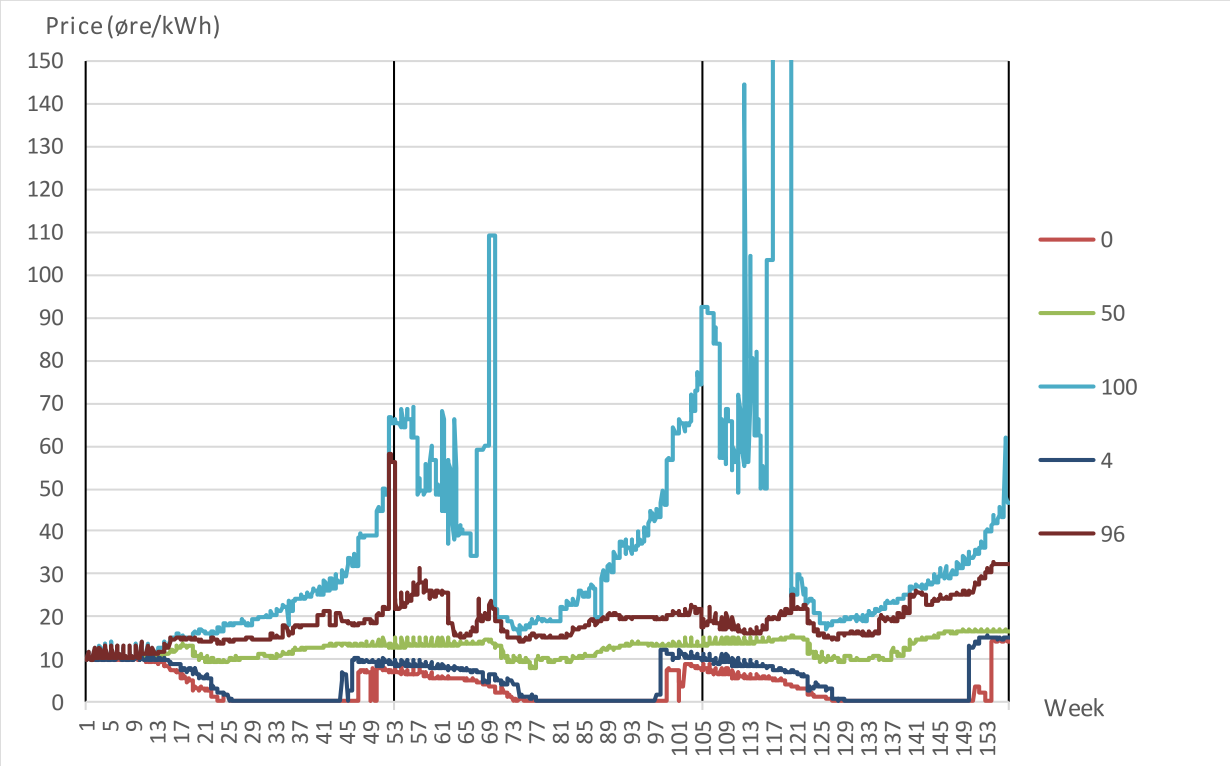

Figure 58 – Base case price, alternative percentile plot, ProdMarket. [40]

The most interesting percentile is the 96-percentile (as the price span is larger on the upside of the mean). Both EMPS and ProdMarket have relatively similar levels for this, for the most time. The bottom figure shows how, apart from one peak, ProdMarket's third highest recorded price at any given moment in time generally follows a stable trend. Together, the two plots highlight how, apart from two inflow scenarios, ProdMarket's prices are similarly spaced as that of EMPS.

Scenario A

For the second simulation case, Scenario A, the same relation is seen. The 96-percentile in Figure 59 tells us that there are, for the most time, no more than two to three scenarios displaying very high power prices. Nonetheless, the above calculations indicate that these few scenarios could be contributing heavily in the model comparison. It is not unlikely that around half the observed 108.1 MNOK result difference between the models could be due to the two driest scenarios.

[40] Price axis cut at 150, highest values reach 450 øre/kWh.

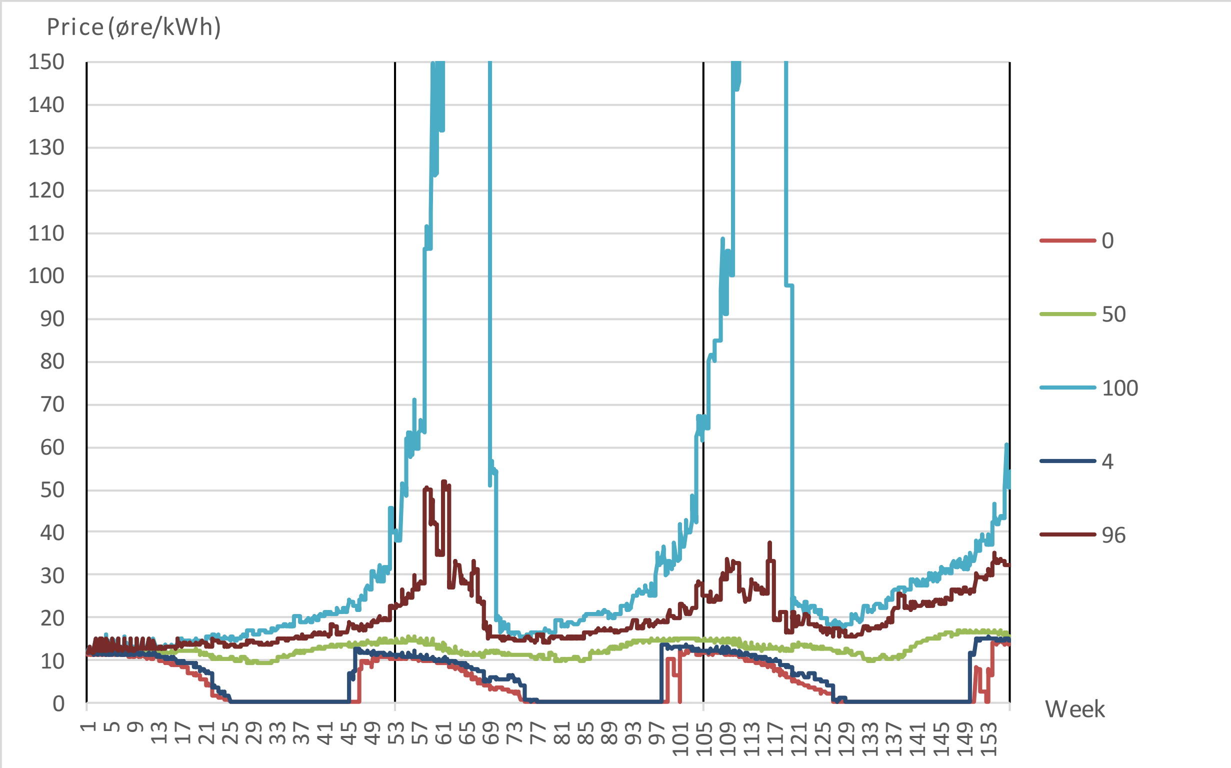

Figure 59 - Scenario A price, alternative percentile plot, ProdMarket. [41]

Figure 60 below is the EMPS equivalent to Figure 59. Once again, it shows how ProdMarket's 96 percentile is not that different from EMPS's, even though the 100-percentile is much higher for almost the entire simulation period.

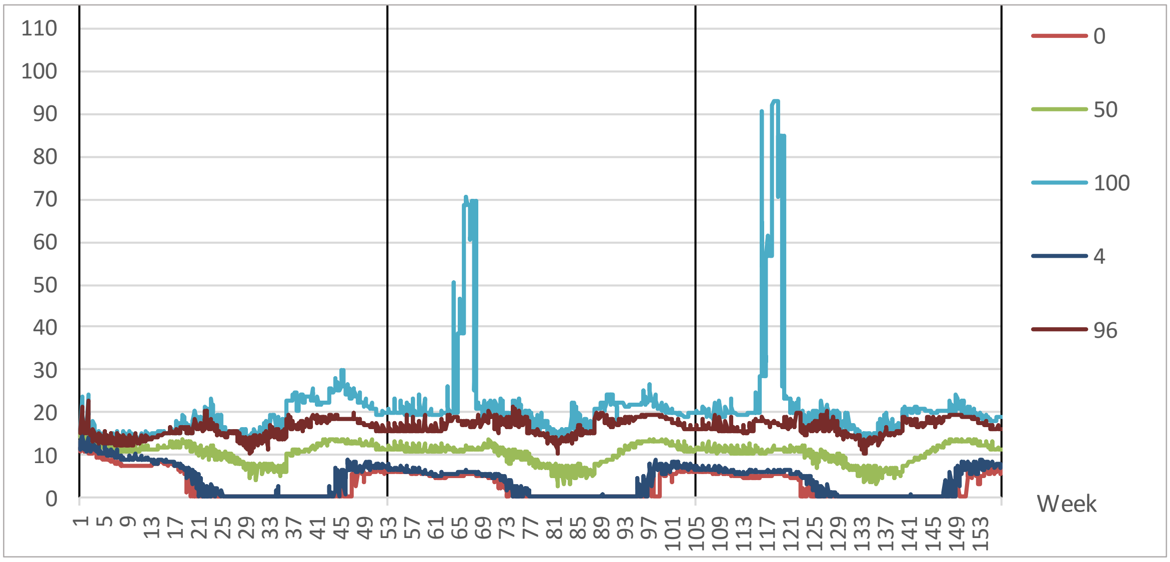

Figure 60 - Scenario A price, alternative percentile plot, EMPS. Cropped.

[41] Price axis cut at 150, highest values reach 450 øre/kWh.

Scenario B

Finally, for Scenario B, only ProdMarket's curve is plotted as the EMPS plot has little variation for any percentile. Figure 61, below, yet again shows how the 96-percentile does not reflect the price levels of the two most extreme inflow scenarios.

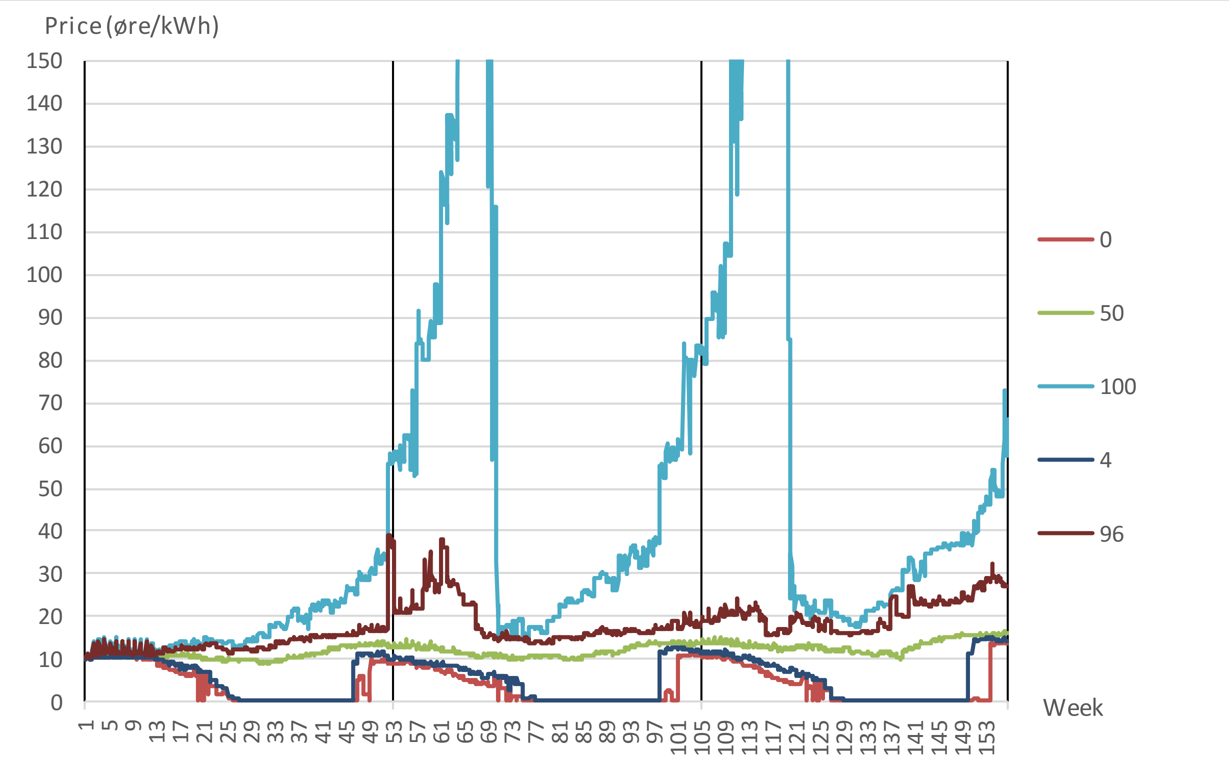

Figure 61 – Scenario B price, alternative percentile plot, ProdMarket. [42]

Summing up price model observations

Based on the above plots, there are at least reasons to suspect ProdMarket of having troubles with extreme values: There is an observable trend both here and throughout this chapter that suggest ProdMarket has larger differences than EMPS between the most extreme results and the main bulk of inflow scenarios. But moving from that observation to a conclusion is not straightforward. It does not necessarily prove that the price model causes exaggerated extreme values which, in turn, completely ruins ProdMarket's overall economic results. It could very well have been optimal to run the system harder than EMPS does, hence offering the economic results in a few scenarios for improved results in the remaining ones.

The hypothesis would be strengthened if a negative trend could be shown as more iterations were run. The plots show no strong trend. Although the 4 and 96-percentile might be said to

[42] Price axis cut at 150, highest values reach 450 øre/kWh.

converge ever-so-slightly from Figure 58 through Figure 59 to Figure 61, the change of case simulation might be just as large a factor. Results would be clearer if individual iterations performed on a single data set were compared.

Here, the last thing to be brought into this discussion is the effect of the worst inflow scenario on overall economic results. Similar to how the 100-percentile price graph can be extracted, the ET-module can also provide percentiles for the economic numbers that make up the mean. Unlike the price and magazine plots, however, ET the economic percentiles are actual inflow years, sorted by inflow numbers. It turns out that the 0-percentile is, not unexpectedly, correlated with the inflow year of 1940. A closer analysis of the economic results shows how the costs related to this inflow scenario year increases steadily from one case to another. For the Base case, the 1940 inflow scenario shows net costs totalling roughly 1450 MNOK. This has a substantial negative contribution to the mean: $\frac{-1450}{50} \approx -29$ MNOK. The corresponding number for Scenario A and B is 1530 and 1620 MNOK, respectively. Meanwhile, EMPS's worst scenario moves from a cost of around -290 MNOK in the Base case to +415 MNOK in Scenario B. Again, the results are not directly comparable, and hold little weight on their own, but they add to the bulk of results indicating a major difference between ProdMarket's and EMPS's results. This is not necessarily where ProdMarket loses ground, but it represents a considerable potential for where it might have.

Summing up the discussion on issues regarding the price model and extreme values, there is no rigid conclusion to be reached. There are indeed some observations that *might* be due to sub-optimal handling of extreme values, but no conclusion can be reached at this stage. As for the problem with end valuation, further work is required.

Chapter 7 Conclusion

The main objective of the work performed has been to assess ProdMarket's performance by running a series of simulations. Three cases have been simulated. Together, the three form a scenario analysis of future changes to the Norwegian power system.

Results for the simulation case representing the present Norwegian system is very good compared to EMPS. But for the two future scenarios, ProdMarket shows poor results. EMPS increasingly outperforms ProdMarket as the simulation cases increase parameters such as intermittent generation. Simulated operating costs are heavily affected by expenses related to buying variable power sources such as thermal power. ProdMarket's poor economic results are not apparent looking at other aspects such as power prices; generally, results seem both realistic and reasonable. On several aspects, ProdMarket also shows how its superior detail level during optimization allows it to handle complex factors such as load and production balancing more effectively than the EMPS model.

There is no observable potential for consistent daily pumping cycles. Moreover, smaller observed short-term price oscillations for ProdMarket than for EMPS raises the question whether balancing potential is not fully represented in ProdMarket – but the analysis suggests the opposite is true: Price oscillations in the system does not warrant large amounts of short-term pumping simply because there is so much available flexibility in production regulation. ProdMarket seems able to utilize this flexibility to a much larger extent than EMPS – this is considered the main reason why ProdMarket's short-term price fluctuations are lower than EMPS's. Improved energy balance in the future scenario simulations is considered a notable aspect on the subject of balancing: Reducing seasonal storage needs means that fewer magazines are emptied, hence increasing the availability of balancing from regular and pumped hydropower.

The most obvious error in the results is that ProdMarket stores excessive amounts of water in hydropower magazines towards the end of the simulation period. This is attributed to weaknesses in using EOPS for internal end-of-period water valuation. The particular settings of this thesis have identified two main factors to contribute to inaccuracies: A software bug in the internal 1toNVV-module, and the fact that EOPS does not include wind power in its calculations.

The price model handles the main interaction between the global and local simulation modules in ProdMarket. In addition to the problem with flawed end valuation, the price model is suggested as a potential contributor to the poor economic results. Concrete evidence of this is scarce, but there is circumstantial evidence: Previous work with ProdMarket has shown good results when intermittent power is placed on the local level; poor results are now seen as intermittency is increased on the global level.

Overall, ProdMarket shows reasonable simulated system operation, but economic results are substantially below par. Assessing the economic loss suffered as a results of each of the two main problem factors presented is challenging. As a consequence, there is a great deal of uncertainty related to ProdMarket's future potential.

7.1 Further work

Based on the analysis performed, the following aspects are considered most relevant for future work:

- **Bug fixes** – refer to Section 4.3.2.
- Improve **price model**, i.e. method for incorporating market price stochasticity in local optimization.
    - o Further work should be performed to isolate and describe the problem – e.g. by comparing results between iterations on the same data set.
    - o It is unclear how, if at all, problems regarding extreme values in the price model can be improved. Major structural changes of the modelling approach could be required.
- Improve **valuation of water at end of the simulation period**.
    - o Fix 1toNVV-module.
    - o Improve on EOPS to include wind, or consider using EMPS for end valuation.
- Include **transmission capacity** constraints. Increases realism on larger systems, and comparability to EMPS.
    - o Could allow for using EMPS to set start-up-conditions and/or end valuation, as opposed to EOPS. That could, however, require calibration of EMPS, which is in itself a task that ProdMarket was thought to be able to avoid.
- Decrease **computation time**.
    - o This thesis lowered calculation times from over 48 hours to roughly 24 hours per iteration (of which 10 was run per simulation) by improving run settings

    and enabling two-level parallelisation. This shows the importance of correct settings.
    - Further improvement of the model should improve method for allocation of cores, e.g. using measured computation time per waterway from the first iteration. Refer to Section 4.3.5.

- Improve **user interface**. Considerable time is spent navigating through sub-optimal interfaces.

- Improve **result analysing of pumped storage**: Use internal water values to estimate surplus from reversible pumping.

    - Using mean production levels and prices is not optimal. Ideally, all scenarios should be analysed separately; the results could then subsequently be averaged. This can be done manually, but require some effort using either spreadsheet software such as Excel or programming languages such as Matlab. Built-in result analysing tools are preferable.

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Appendix A – EMPS settings

This Appendix holds additional run setting for EMPS.

Table 25 shows the settings used in EMPS simulations.

Table 25 - EMPS settings

Setting	Value
Series or parallel simulation	Parallel
First week to simulate	1
Last week to simulate	156
Number of inflow scenarios	50
Inflow years used	1931-1980
First week of filling season	18
First week of discharge season	40
Magazine levels first week, all magazines.	70
Number of price periods per week	16

These settings are set so that EMPS runs with similar settings as ProdMarket, shown in Appendix B.

Table 26 - EMPS settings, calculation parameters

```
--------- Beregningsparametre ---------

Parameter Verdi  Stikkord
  IT        340   Maks. antall iterasjoner, opplasting trinn 2
  TR        0.1  Maksimal trinnst|rrelse under opplastingen (p.u.)
  KO        0.5  Konvergenskrav til produksjon (MW)
  PU       0.01  Pumpekonstant
  PK    10000.0  H|yeste kraftverdi for drift av pumpekraftverk
  PL       0.01  H|yeste kraftverdi for p}lagtpumping i pumpekraftverk
  V]         18  V}ruken
  H\         40  H|stuken
  SK       1.50  Skaleringsfaktor for vannverdi

  OMR            Innleste delomr}der skrives ut p} skjerm
```

Appendix B – ProdMarket settings

The table below shows a summary of the file “INITIALISERING.PDMARKED” for the Base case. It holds parameters used by ProdMarket.

Table 27 – ProdMarket settings set in the file “INITIALISERING.PDMARKED”

Setting	Value
Path to data set	D:\Vegard\BaseCase
Name, main area	HODE
Name, main price series	x1.csv
Series or parallel simulation	Parallel
Magazine levels first week, all magazines	70
First week to simulate	1
Last week to simulate	156
Maximum number of main loop iterations	10
Maximum allowable absolute value change in power value between main iterations	10.0
Maximum deviation in power value between main iterations, in # of standard deviations	4.0
Maximum number of processor cores to use	8
LP solver (COIN/CPLEX)	CPLEX
Use Message Passing Interface (MPI)?	yes
Weighing of new price series in next main iteration	0.3
Number of cuts used in each watercourse	500
Maximum number of iterations for ProdRisk in each watercourse	50
Method used to update water values	Vansimtap
Version of Vansimtap (setting not in use)	Vansim
Version of Genpris used	Genpris

Appendix C – Regression analysis of Norway anno 2014

All input data come from SSB (Statistisk sentralbyrå, 2015, n.d.-a, n.d.-b). Regression figure is based on linear regression of observed data.

Table 28 – Regression analysis of total power production, Norway 2014.

Year	Total production (GWh)	Total production (TWh)
2000	142816	143
2001	121608	122
2002	130473	130
2003	107245	107
2004	110472	110
2005	137811	138
2006	121400	121
2007	137164	137
2008	142108	142
2009	131773	132
2010	123630	124
2011	127631	128
2012	147716	148
2013	133975	134
2014	141968	142
Regression 2014	137623	**138**

Table 29 – Regression analysis of hydropower production, Norway 2014.

Year	Production (GWh)	Production (TWh)
2000	142289	142
2002	129837	130
2004	109291	109
2006	119729	120
2007	134736	135
2008	139981	140
2009	126077	126
2010	117152	117
2011	121553	122
2012	142810	143
2013	128699	129
2014	136181	136
Regression 2014	129825	**130**

Table 30 - Regression analysis of generation mix, Norway 2014. All numbers in percent.

Year	Hydro	Thermal	Wind
2000	99.63	0.35	0.02
2002	99.42	0.43	0.06
2004	98.93	0.84	0.23
2006	98.62	0.85	0.52
2007	98.23	1.12	0.65
2008	98.50	0.85	0.64
2009	95.68	3.58	0.74
2010	94.76	4.53	0.71
2011	95.24	3.76	1.01
2012	96.68	2.27	1.05
2013	96.06	2.53	1.40
2014	95.92	2.51	1.56
Regression 2014	**95.29**	**3.36**	**1.36**

Table 31 – Regression analysis of net export, Norway 2014.

Year	Export (GWh)	Export (TWh)
2000	19055	19.06
2002	9711	9.71
2004	-11492	-11.49
2006	-855	-0.86
2007	10036	10.04
2008	13877	13.88
2009	8983	8.98
2010	-7550	-7.55
2011	3074	3.07
2012	17816	17.82
2013	5005	5.01
2014	15585	15.59
Regression 2014	7499	**7.50**

Regression analysis of total production and export suggest load level of about $138 - 8 = 130$ TWh.

Appendix D – Price periods

The text box below show the sixteen price periods used during simulations. All hours of each day is assigned to a price period. See more in section 4.3.4.

```
  1,  * Versjonsnummer p} fil
  16,  * Antall prisavsnitt
  1,'Ukedag_Time1-3     ',* Avsnitt nr, Navn
  2,'Ukedag_Time4-6     '
  3,'Ukedag_Time7-9     '
  4,'Ukedag_Time10-12   '
  5,'Ukedag_Time13-15   '
  6,'Ukedag_Time16-18   '
  7,'Ukedag_Time19-21   '
  8,'Ukedag_Time22-24   '
  9,'Helg_Time1-3     '
  10,'Helg_Time4-6     '
  11,'Helg_Time7-9     '
  12,'Helg_Time10-12   '
  13,'Helg_Time13-15   '
  14,'Helg_Time16-18   '
  15,'Helg_Time19-21   '
  16,'Helg_Time22-24   '
  1,  1,  1,  2,  2,  2,  3,  3,  3,  4,  4,  4,  5,  5,  5,  6,  6,  6,  7,  7,  7,  8,  8,  8,Mon
  1,  1,  1,  2,  2,  2,  3,  3,  3,  4,  4,  4,  5,  5,  5,  6,  6,  6,  7,  7,  7,  8,  8,  8,Tue
  1,  1,  1,  2,  2,  2,  3,  3,  3,  4,  4,  4,  5,  5,  5,  6,  6,  6,  7,  7,  7,  8,  8,  8,Wed
  1,  1,  1,  2,  2,  2,  3,  3,  3,  4,  4,  4,  5,  5,  5,  6,  6,  6,  7,  7,  7,  8,  8,  8,Thu
  1,  1,  1,  2,  2,  2,  3,  3,  3,  4,  4,  4,  5,  5,  5,  6,  6,  6,  7,  7,  7,  8,  8,  8,Fri
  9,  9,  9,  10,  10,  10,  11,  11,  11,  12,  12,  12,  13,  13,  13,  14,  14,  14,  15,  15,  15,
16,  16,  16,Sat
  9,  9,  9,  10,  10,  10,  11,  11,  11,  12,  12,  12,  13,  13,  13,  14,  14,  14,  15,  15,  15,
16,  16,  16,Sun
```

Figure 62 – File "PRISAVSNITT.DATA".

Appendix E – Implementation of Base case

Table 32 – Contractual obligations in “HODE”, ProdMarket. Base case.

```
Oversikt over kontraktsforpliktelser/rettigheter
------------------------------------------------------------
Del- : Kate- : Navn p}              :EGET:PRISAV:     }r      :
last : gori  : delbelastning        :    :TEMPAV: 2003-2005   :
 nr  :       :                      :    :  P/T :   (GWh)     :
------------------------------------------------------------
  1  : FORPL : ALM. FORSYNING-NUMED:    :      :    6210.00 :
  2  : FORPL : INDUSTRI 95-NUMEDAL :    :      :    2775.00 :
 11  : FORPL : FASTKRAFTPROGNO-TEV :    :      :    6300.00 :
 15  : FORPL : KO.KR SKJ]K SOMMER-T:    :      :      26.61 :
 16  : FORPL : KO.KR SKJ]K VINTER-T:    :      :      39.60 :
 17  : FORPL : KO.KR GRYTTEN SOMMER:    :      :       5.40 :
 18  : FORPL : KO.KR GRYTTEN VINTER:    :      :      12.60 :
 19  : FORPL : KO.KR NORDDAL SOMMER:    :      :      52.32 :
 20  : FORPL : KO.KR NORDDAL VINTER:    :      :     111.00 :
 31  : FORPL : FASTKRAFT-OTRA      :    :      :    9900.00 :
 32  : FORPL : FASTKRAFTPROGNO-TERM:    :      :    1050.00 :
------------------------------------------------------------
Sum forpliktelser - rettigheter            :   26482.53 :
------------------------------------------------------------
```

Table 33 - Details of contractual obligation "Fastkraftprognose" in “HODE”, ProdMarket. Base case.

```
Kontrakt nummer   32, FASTKRAFTPROGNO-TERM
Type: FORPL
Uttaksprofil:                       PL_INDUSTRI 95
Temperaturkorrigeringsprofil:
Effektprofil:                       PE_FASTKRAFTPROGNO
Plassering: TOTAL
------------------------------------------------
: Per.: Tidsperiode    : Kontrakts-  :  Pris    :
: -nr : Start : Slutt  :  kvantum    :          :
:     :  uke  :  uke   :   (GWH)     :(|re/kWh):
------------------------------------------------
:   1 :    1  :    52  :    350.00   :    0.00 :
:   2 :   53  :   104  :    350.00   :    0.00 :
:   3 :  105  :   156  :    350.00   :    0.00 :
```

Table 34 – Contractual obligations in “TERM”, EMPS. Base case.

```
Oversikt over kontraktsforpliktelser/rettigheter
------------------------------------------------------------
Del- : Kate- : Navn p}              :EGET:PRISAV:     }r      :
last : gori  : delbelastning        :    :TEMPAV: 2003-2005   :
 nr  :       :                      :    :  P/T :   (GWh)     :
------------------------------------------------------------
  1  : FORPL : FASTKRAFTPROGNO      :    :      :    1050.00 :
------------------------------------------------------------
Sum forpliktelser - rettigheter            :    1050.00 :
------------------------------------------------------------
```

Table 35 - Details of contractual obligation "Fastkraftprognose" in “TERM”, EMPS. Base case.

```
Kontrakt nummer    1, FASTKRAFTPROGNO
Type: FORPL
Uttaksprofil:                  PL_INDUSTRI 95
Temperaturkorrigeringsprofil:
Effektprofil:                  PE_FASTKRAFTPROGNO
Plassering: TOTAL
------------------------------------------------
: Per.: Tidsperiode    : Kontrakts-  :  Pris   :
: -nr : Start : Slutt  :  kvantum    :         :
:     :  uke  :  uke   :   (GWH)     :(|re/kWh):
------------------------------------------------
:   1 :    1  :    52  :    350.00   :    0.00 :
:   2 :   53  :   104  :    350.00   :    0.00 :
:   3 :  105  :   156  :    350.00   :    0.00 :
```

Appendix F – Implementation of Scenario A

Table 36 – Scenario A implementation: Production settings, Brokke power station.

```
Modul nummer 11511, BOSSVATN                                    Eierprosent: 100.0

Type modul:   Vannkraft
-------------------------------------------------------------------------------
 nr.  K o m m e n t a r e r            : nr.  K o m m e n t a r e r
-------------------------------------------------------------------------------
  1   Magasinvolum      (Mm3)      296.0 :      Flagg =  0, Data ikke innlest
      Bunnmagasinvolum (Mm3)        0.0 :      Flagg >  0, Data er innlest
  2   Energiekvivalent (kWh/m3)  0.6806 :      Flagg = -1, Data m} sjekkes
  3   Maks. vassf|ring (m3/s)    176.00 :      Tast DF for detaljforklaring
  4   Midlere fallh|yde (m)      282.00 :
  5   Utl|pskote       (m.o.h.)  248.00 :
                                        :      Restriksjoner      Type   Flagg
  6   Prod.vann til modul           153 : 17   Maksimalmagasin               0
  7   Flomvann til modul            151 : 18   Minimalmagasin     (lokal)    1
  8   Forbitapping til modul        151 : 19   Maksimalvassf|ring            0
  9   Kode for hydraulisk kobling     0 : 20   Minimalvassf|ring             0
 10   Koblingsfaktor eller nummer     0 : 21   Forbitapping                  0
 11   Maks utgj.vassf|ring (m3/s)     0 : 22   Maks. forbitapp. (m3/s) 10000.0

 12   Mid reg. tilsig (Mm3/}r)    762.9 :      Funksjonssammenhenger     Flagg
 13   Serienavn  reg. tilsig
                                   536-B  23   Tappekapasitetsbegrensninger  0
        ]rstilsig ref. perioden 1931-1960 24   Magasinkurve                  1
 14   Mid ureg.tilsig (Mm3/}r)      0.0 : 25   Tappestrategidata             1
 15   Serienavn ureg. tilsig
                                   536-B  26   Prod./vassf|ringskurve(r)     1
 16   Stasjonsnavn: BROKKE              : 27   Pumpemuligheter               0
-------------------------------------------------------------------------------


Søkenr og verdi * RETURN - Data ok * V - Veiledning * .. : 26

Modul nr 11511 BOSSVATN
------------------------------
: Sluttuke *       52        *
------------------------------
:  Knekk-  * Produk : Vass-  *
:  punkt   * -sjon  : f|ring *
:   nr.    *  (MW)  : (m3/s) *
------------------------------
:     1    *   0.00 :   0.00 *
:     2    *  32.80 :  13.60 *
:     3    *  85.80 :  33.80 *
:     4    * 129.90 :  51.70 *
:     5    * 159.00 :  63.70 *
:     6    * 206.30 :  83.30 *
:     7    * 229.60 :  93.40 *
:     8    * 282.60 : 116.70 *
:     9    * 385.90 : 176.00 *
------------------------------
: Energiekv* 0.6806 (kWh/m3) *
------------------------------
```

Table 37 – Scenario A implementation: Pump settings, Holen power station.

```
PUMP : Pumpedata
-----------------

Modul nummer 11513, VATNEDAL
---------------------------------------------------
: Midlere pumpeeffekt                  (MW) :   360.0 :
: St|rste l|fteh|yde                    (m) :   345.0 :
: Tilh|rende pumpekapasitet          (m3/s) :    94.6 :
: Minste l|fteh|yde                     (m) :   149.0 :
: Tilh|rende pumpekapasitet          (m3/s) :   219.0 :
: Nummer p} vannkraftmodul det pumpes til  :  11513  :
: Nummer p} vannkraftmodul det pumpes fra  :  11511  :
---------------------------------------------------

* Er data o. k. ? * ..................................
Styrekurve for magasin det pumpes til
-------------------------------------
: Knekk- : Ukenummer :  Magasin-  :
: punkt  :           :  fylling   :
: nummer :           :    (%)     :
----------------------------------
:    1   :     1     :   100.0    :
:    2   :    52     :   100.0    :

* Er data o. k. ? * ..................................
Styrekurve for magasin det pumpes fra
-------------------------------------
: Knekk- : Ukenummer :  Magasin-  :
: punkt  :           :  fylling   :
: nummer :           :    (%)     :
----------------------------------
:    1   :     1     :     0.0    :
:    2   :    52     :     0.0    :
```

Table 38 – Scenario A implementation: Production settings, Holen power station.

```
Modul nummer 11513, VATNEDAL                                 Eierprosent: 100.0

Type modul:   Vannkraft
-----------------------------------------------------------------------------
 nr.  K o m m e n t a r e r            : nr.  K o m m e n t a r e r
-----------------------------------------------------------------------------
  1   Magasinvolum     (Mm3)     1150.0 :      Flagg =  0, Data ikke innlest
      Bunnmagasinvolum (Mm3)        0.0 :      Flagg >  0, Data er innlest
  2   Energiekvivalent (kWh/m3)  0.7282 :      Flagg = -1, Data m} sjekkes
  3   Maks. vassf|ring (m3/s)    141.20 :      Tast DF for detaljforklaring
  4   Midlere fallh|yde (m)      300.00 :
  5   Utl|pskote       (m.o.h.)  524.00 :
                                        :      Restriksjoner      Type   Flagg
  6   Prod.vann til modul         11511 : 17   Maksimalmagasin              0
  7   Flomvann til modul          11511 : 18   Minimalmagasin               0
  8   Forbitapping til modul      11511 : 19   Maksimalvassf|ring           0
  9   Kode for hydraulisk kobling     0 : 20   Minimalvassf|ring            0
 10   Koblingsfaktor eller nummer     0 : 21   Forbitapping                 0
 11   Maks utgj.vassf|ring (m3/s)     0 : 22   Maks. forbitapp. (m3/s) 10000.0

 12   Mid reg. tilsig (Mm3/}r)    254.3 :      Funksjonssammenhenger     Flagg
 13   Serienavn  reg. tilsig
                                  536-B  23    Tappekapasitetsbegrensninger  0
        ]rstilsig ref. perioden 1931-1960 24   Magasinkurve                  1
 14   Mid ureg.tilsig (Mm3/}r)      0.0 : 25   Tappestrategidata             1
 15   Serienavn ureg. tilsig
                                  536-B  26    Prod./vassf|ringskurve(r)     1
 16   Stasjonsnavn: HOLEN               : 27   Pumpemuligheter               1
-----------------------------------------------------------------------------


Søkenr og verdi * RETURN - Data ok * V - Veiledning * .. : 26

Modul nr 11513 VATNEDAL
------------------------------
: Sluttuke *       52        *
------------------------------
:  Knekk-  * Produk : Vass-  *
:  punkt   * -sjon  : f|ring *
:   nr.    *  (MW)  : (m3/s) *
------------------------------
:     1    *   0.00 :   0.00 *
:     2    *  91.40 :  36.00 *
:     3    * 152.30 :  55.40 *
:     4    * 189.70 :  73.40 *
:     5    * 297.70 : 110.80 *
:     6    * 360.00 : 141.20 *
------------------------------
: Energiekv* 0.7282 (kWh/m3) *
------------------------------
```

Table 39 - Contractual obligation "Fastkraftprognose" in "HODE", ProdMarket. Scenario A.

```
Kontrakt nummer   32, FASTKRAFTPROGNO-TERM
Type: FORPL
Uttaksprofil:                   PL_INDUSTRI 95
Temperaturkorrigeringsprofil:
Effektprofil:                   PE_FASTKRAFTPROGNO
Plassering: TOTAL
------------------------------------------------
: Per.: Tidsperiode    : Kontrakts-  :  Pris    :
: -nr : Start : Slutt  :  kvantum    :          :
:     :  uke  :  uke   :   (GWH)     :(|re/kWh):
------------------------------------------------
:   1 :    1  :    52  :    410.00   :    0.00 :
:   2 :   53  :   104  :    410.00   :    0.00 :
:   3 :  105  :   156  :    410.00   :    0.00 :
```

Appendix G – Implementation of Scenario B

Table 40 – Scenario B implementation: Production settings, Brokke power station.

```
Modul nummer 11511, BOSSVATN                                  Eierprosent: 100.0

Type modul:   Vannkraft
-----------------------------------------------------------------------------
 nr.  K o m m e n t a r e r           : nr.  K o m m e n t a r e r
-----------------------------------------------------------------------------
  1   Magasinvolum      (Mm3)     296.0 :      Flagg =  0, Data ikke innlest
      Bunnmagasinvolum (Mm3)        0.0 :      Flagg >  0, Data er innlest
  2   Energiekvivalent (kWh/m3)  0.6806 :      Flagg = -1, Data m} sjekkes
  3   Maks. vassf|ring (m3/s)    176.00 :      Tast DF for detaljforklaring
  4   Midlere fallh|yde (m)      282.00 :
  5   Utl|pskote       (m.o.h.)  248.00 :
                                        :      Restriksjoner      Type   Flagg
  6   Prod.vann til modul           153 : 17   Maksimalmagasin               0
  7   Flomvann til modul            151 : 18   Minimalmagasin     (lokal)    1
  8   Forbitapping til modul        151 : 19   Maksimalvassf|ring            0
  9   Kode for hydraulisk kobling     0 : 20   Minimalvassf|ring             0
 10   Koblingsfaktor eller nummer     0 : 21   Forbitapping                  0
 11   Maks utgj.vassf|ring (m3/s)     0 : 22   Maks. forbitapp. (m3/s) 10000.0

 12   Mid reg. tilsig (Mm3/}r)    762.9 :      Funksjonssammenhenger     Flagg
 13   Serienavn  reg. tilsig
                                  536-B  23    Tappekapasitetsbegrensninger  0
        ]rstilsig ref. perioden 1931-1960 24   Magasinkurve                  1
 14   Mid ureg.tilsig (Mm3/}r)      0.0 : 25   Tappestrategidata             1
 15   Serienavn ureg. tilsig
                                  536-B  26    Prod./vassf|ringskurve(r)     1
 16   Stasjonsnavn: BROKKE              : 27   Pumpemuligheter               0
-----------------------------------------------------------------------------


Søkenr og verdi * RETURN - Data ok * V - Veiledning * .. : 26

Modul nr 11511 BOSSVATN
------------------------------
: Sluttuke *       52        *
------------------------------
:  Knekk-  * Produk : Vass-  *
:  punkt   * -sjon  : f|ring *
:   nr.    *  (MW)  : (m3/s) *
------------------------------
:     1    *   0.00 :   0.00 *
:     2    *  32.80 :  13.60 *
:     3    *  85.80 :  33.80 *
:     4    * 129.90 :  51.70 *
:     5    * 159.00 :  63.70 *
:     6    * 206.30 :  83.30 *
:     7    * 229.60 :  93.40 *
:     8    * 282.60 : 116.70 *
:     9    * 385.90 : 176.00 *
------------------------------
: Energiekv* 0.6806 (kWh/m3) *
------------------------------
```

Table 41 – Scenario B implementation: Production settings, Nore power station.

```
Modul nummer  7303, TUNNHOVFJORD                         Eierprosent: 100.0

Type modul:   Vannkraft
------------------------------------------------------------------------------
 nr.  K o m m e n t a r e r          : nr.  K o m m e n t a r e r
------------------------------------------------------------------------------
  1   Magasinvolum     (Mm3)      352.0 :      Flagg =  0, Data ikke innlest
      Bunnmagasinvolum (Mm3)        0.0 :      Flagg >  0, Data er innlest
  2   Energiekvivalent (kWh/m3)  0.7900 :      Flagg = -1, Data m} sjekkes
  3   Maks. vassf|ring (m3/s)     98.40 :      Tast DF for detaljforklaring
  4   Midlere fallh|yde (m)      370.00 :
  5   Utl|pskote        (m.o.h.)  360.00 :
                                        :      Restriksjoner      Type   Flagg
  6   Prod.vann til modul          7304 : 17   Maksimalmagasin               0
  7   Flomvann til modul           7304 : 18   Minimalmagasin                0
  8   Forbitapping til modul       7304 : 19   Maksimalvassf|ring            0
  9   Kode for hydraulisk kobling     0 : 20   Minimalvassf|ring             0
 10   Koblingsfaktor eller nummer     0 : 21   Forbitapping                  0
 11   Maks utgj.vassf|ring (m3/s)     0 : 22   Maks. forbitapp. (m3/s)    10.0

 12   Mid reg. tilsig (Mm3/}r)    245.0 :      Funksjonssammenhenger     Flagg
 13   Serienavn  reg. tilsig
                                  467-A  23    Tappekapasitetsbegrensninger  0
        ]rstilsig ref. perioden 1931-1960 24   Magasinkurve                  1
 14   Mid ureg.tilsig (Mm3/}r)      0.0 : 25   Tappestrategidata             1
 15   Serienavn ureg. tilsig
                                  467-A  26    Prod./vassf|ringskurve(r)     1
 16   Stasjonsnavn: NORE 1              : 27   Pumpemuligheter               0
------------------------------------------------------------------------------


Søkenr og verdi * RETURN - Data ok * V - Veiledning * .. : 26

Modul nr  7303 TUNNHOVFJORD
------------------------------
: Sluttuke *       52        *
------------------------------
:  Knekk-   * Produk : Vass-   *
:  punkt    * -sjon  : f|ring *
:    nr.    *  (MW)  : (m3/s) *
------------------------------
:     1     *   0.00 :    0.00 *
:     2     * 280.00 :   98.40 *
------------------------------
: Energiekv* 0.7900 (kWh/m3) *
------------------------------
```

Table 42 – Scenario B implementation: Pump settings, Holen power station.

```
PUMP : Pumpedata
-----------------

Modul nummer 11513, VATNEDAL
-----------------------------------------------------
: Midlere pumpeeffekt                   (MW) :   500.0 :
: St|rste l|fteh|yde                     (m) :   345.0 :
: Tilh|rende pumpekapasitet           (m3/s) :   131.5 :
: Minste l|fteh|yde                      (m) :   149.0 :
: Tilh|rende pumpekapasitet           (m3/s) :   304.4 :
: Nummer p} vannkraftmodul det pumpes til  :  11513   :
: Nummer p} vannkraftmodul det pumpes fra  :  11511   :
-----------------------------------------------------

* Er data o. k. ? * ..................................
Styrekurve for magasin det pumpes til
-------------------------------------
: Knekk- : Ukenummer :  Magasin- :
: punkt  :           :  fylling  :
: nummer :           :    (%)    :
----------------------------------
:    1   :     1     :   100.0   :
:    2   :    52     :   100.0   :

* Er data o. k. ? * ..................................
Styrekurve for magasin det pumpes fra
-------------------------------------
: Knekk- : Ukenummer :  Magasin- :
: punkt  :           :  fylling  :
: nummer :           :    (%)    :
----------------------------------
:    1   :     1     :     0.0   :
:    2   :    52     :     0.0   :
```

Table 43 – Scenario B implementation: Production settings, Holen power station.

```
Modul nummer 11513, VATNEDAL                                     Eierprosent: 100.0

Type modul:   Vannkraft
-------------------------------------------------------------------------------
 nr.  K o m m e n t a r e r           : nr.  K o m m e n t a r e r
-------------------------------------------------------------------------------
  1   Magasinvolum     (Mm3)     1150.0 :      Flagg =  0, Data ikke innlest
      Bunnmagasinvolum (Mm3)        0.0 :      Flagg >  0, Data er innlest
  2   Energiekvivalent (kWh/m3)  0.7282 :      Flagg = -1, Data m} sjekkes
  3   Maks. vassf|ring (m3/s)    196.20 :      Tast DF for detaljforklaring
  4   Midlere fallh|yde (m)      300.00 :
  5   Utl|pskote       (m.o.h.)  524.00 :
                                        :      Restriksjoner      Type   Flagg
  6   Prod.vann til modul         11511 : 17   Maksimalmagasin              0
  7   Flomvann til modul          11511 : 18   Minimalmagasin               0
  8   Forbitapping til modul      11511 : 19   Maksimalvassf|ring           0
  9   Kode for hydraulisk kobling     0 : 20   Minimalvassf|ring            0
 10   Koblingsfaktor eller nummer     0 : 21   Forbitapping                 0
 11   Maks utgj.vassf|ring (m3/s)     0 : 22   Maks. forbitapp. (m3/s) 10000.0

 12   Mid reg. tilsig (Mm3/}r)    254.3 :      Funksjonssammenhenger     Flagg
 13   Serienavn  reg. tilsig
                                  536-B  23    Tappekapasitetsbegrensninger  0
        ]rstilsig ref. perioden 1931-1960 24   Magasinkurve                  1
 14   Mid ureg.tilsig (Mm3/}r)      0.0 : 25   Tappestrategidata             1
 15   Serienavn ureg. tilsig
                                  536-B  26    Prod./vassf|ringskurve(r)     1
 16   Stasjonsnavn: HOLEN               : 27   Pumpemuligheter               0
-------------------------------------------------------------------------------


Søkenr og verdi * RETURN - Data ok * V - Veiledning * .. : 26

Modul nr 11513 VATNEDAL
------------------------------
: Sluttuke *       52        *
------------------------------
:  Knekk-   * Produk : Vass-   *
:  punkt    * -sjon  : f|ring *
:   nr.     *  (MW)  : (m3/s) *
------------------------------
:     1    *   0.00 :   0.00 *
:     2    * 126.90 :  50.00 *
:     3    * 211.50 :  76.90 *
:     4    * 263.50 : 101.90 *
:     5    * 413.50 : 153.80 *
:     6    * 500.00 : 196.20 *
------------------------------
: Energiekv* 0.7282 (kWh/m3) *
------------------------------
```

Table 44 - Contractual obligation "Fastkraftprognose" in “HODE”, ProdMarket. Scenario B.

```
Kontrakt nummer   32, FASTKRAFTPROGNO-TERM
Type: FORPL
Uttaksprofil:                 PL_INDUSTRI 95
Temperaturkorrigeringsprofil:
Effektprofil:                 PE_FASTKRAFTPROGNO
Plassering: TOTAL
------------------------------------------------
: Per.: Tidsperiode    : Kontrakts-  :  Pris   :
: -nr : Start : Slutt  :  kvantum    :         :
:     :  uke  :  uke   :   (GWH)     :(|re/kWh):
------------------------------------------------
:   1 :    1  :    52  :    410.00   :    0.00 :
:   2 :   53  :   104  :    410.00   :    0.00 :
:   3 :  105  :   156  :    410.00   :    0.00 :
```

Appendix H – Results, corrected EMPS run of Scenario A

Table 25 shows the main energy-related and economic results from the re-run of Scenario A in EMPS with corrected calibration settings. The corrected setting meant that the calibration parameter “elasticity factor” was set to 1, as indicated by Table 7 on page 34, instead of 0 as in the erroneous Scenario A calibration setting used in the results and analysis. Differences were found too small to affect the analysis. Magazine handling were also close to identical.

Table 45 - Results, corrected EMPS run of Scenario A

	Unit	Numedal	TEV	EMPS Otra	Term	**Total**	**Difference to SA**
Inflow	GWh	9315.8	7364.0	11086.3		27766.1	3.9
Spillage and bypass	GWh	558.0	710.0	656.3		1924.3	-2.9
Pumping, use	GWh			455.2		455.2	4.6
Pumping, gain	GWh			652.5		652.5	5.7
Pumping, net	GWh			197.3		197.3	1.1
Start magazine, sum	GWh	1070.8	1125.0	2003.9		4199.7	0.0
End magazine, sum	GWh	901.7	1096.0	2297.7		4295.4	-7.2
							0.0
Contracted power demand	GWh	8985.0	6547.5	9900.0	1230.0	26662.5	0.0
Delivered hydropower	GWh	8926.9	6682.9	10333.6		25943.4	15.0
Contracted power not deliv.	GWh	0.2	0.0	0.3	0.0	0.5	-0.8
Interruptible load bought	GWh	121.2	0.0	154.8	487.6	763.6	-11.6
Interruptible load sold	GWh	878.3	30.0	432.5	30.0	1370.8	2.6
Wind power, Norway	GWh				1326.0	1326.0	0.0
UK wind and GE PV, net	GWh				-0.1	-0.1	0.0
							0.0
Contracted power not deliv.	MNOK	0.2	0.0	0.2	0.0	0.4	1.3
Net income	MNOK	43.7	-10.8	94.9	-17.5	110.3	137.7
Magazine level changes	MNOK	-19.5	-5.5	24.4	0.0	-0.6	-0.8
Net income, magazine adj.	MNOK	24.3	-16.3	119.2	-17.5	109.7	136.9

Appendix I – Calibration EMPS

This appendix holds sum reservoir plots used to validate EMPS calibration. Each of the three hydropower areas are plotted per calibration. First, the four settings tested in Section 4.1.1 for the Base case is presented. Then, the chosen calibration, “Manual 2” is shown for Scenario A and B.

Base case calibration setups

“Default” calibration setup

Below follow the sum reservoir levels for each of the three hydropower areas using the “Default” calibration.

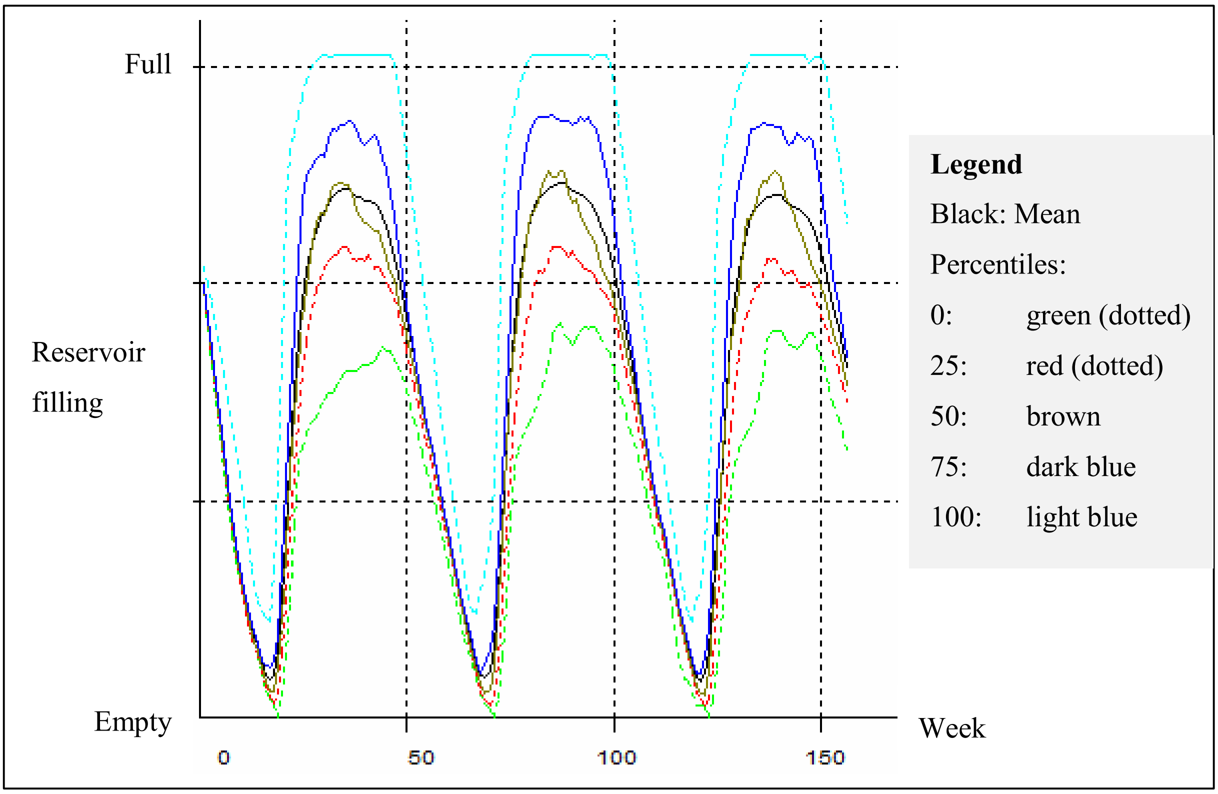

Figure 63 – Numedal sum reservoir level using EMPS calibration setting "Default". Base case data set. Identical to Figure 4.

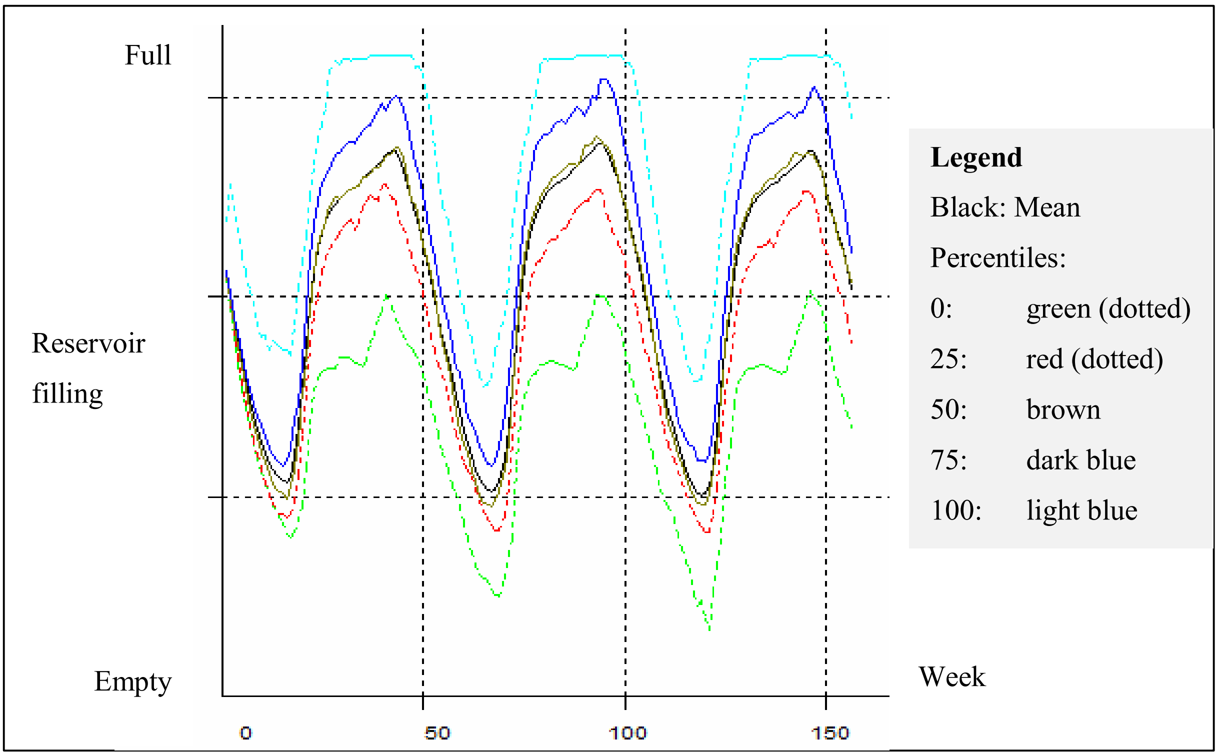

Figure 64 – TEV sum reservoir level using EMPS calibration setting "Default". Base case data set.

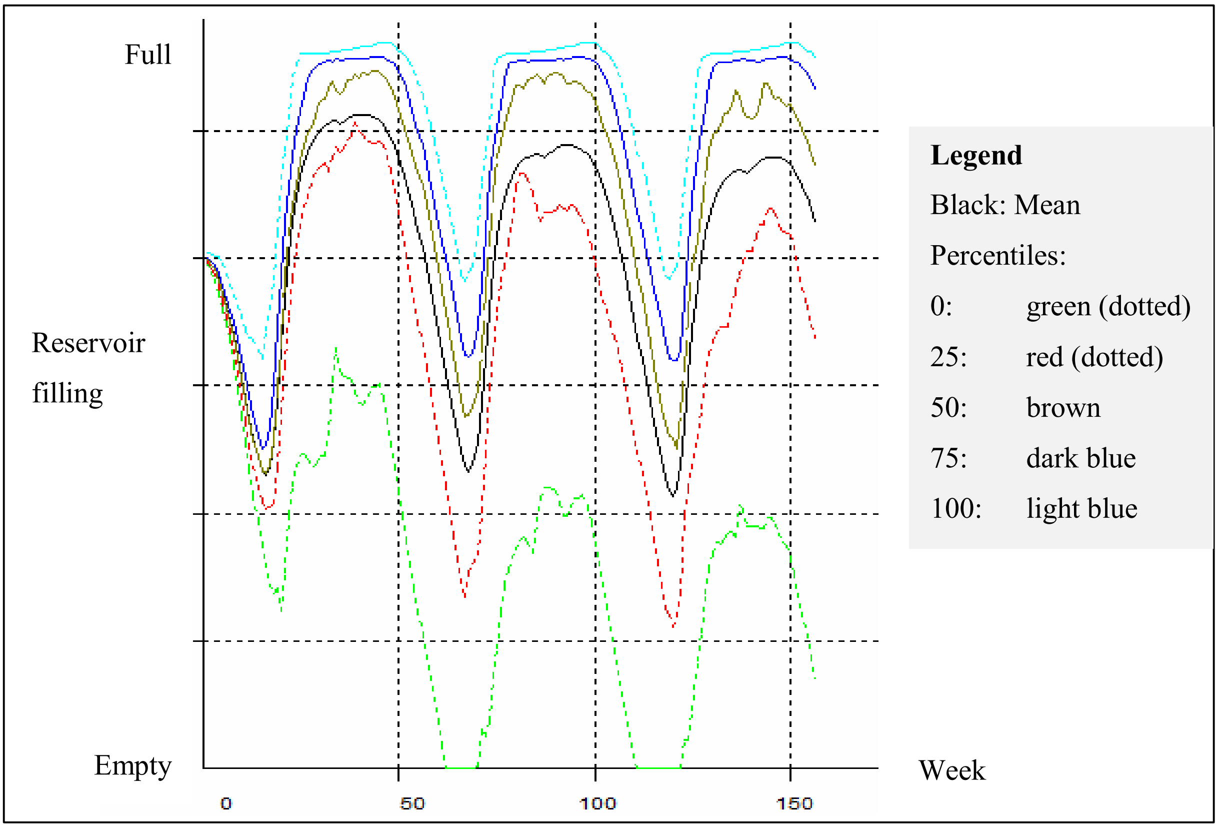

Figure 65 – Otra sum reservoir level using EMPS calibration setting "Default". Base case data set.

“Manual 1” calibration setup

Below follow the sum reservoir levels for each of the three hydropower areas using the “Manual 1” calibration.

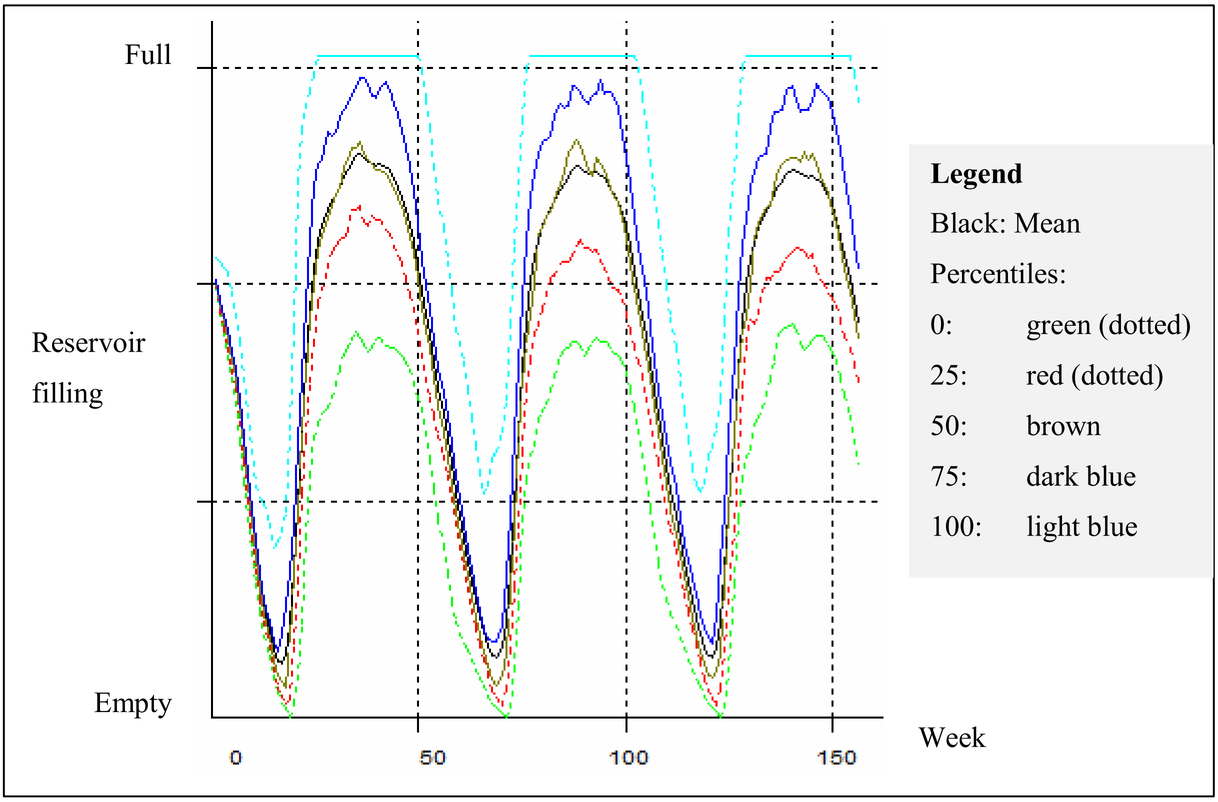

Figure 66 – Numedal sum reservoir level using EMPS calibration setting "Manual 1". Base case data set.

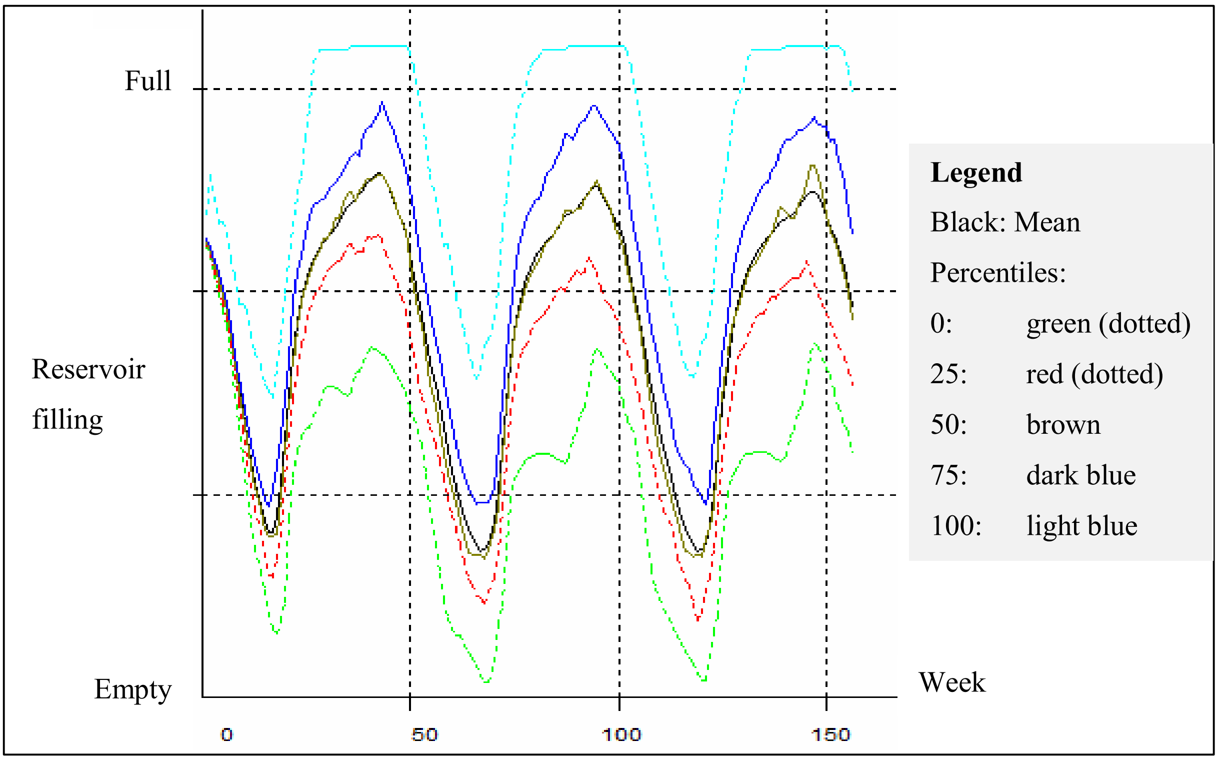

Figure 67 – TEV sum reservoir level using EMPS calibration setting "Manual 1". Base case data set.

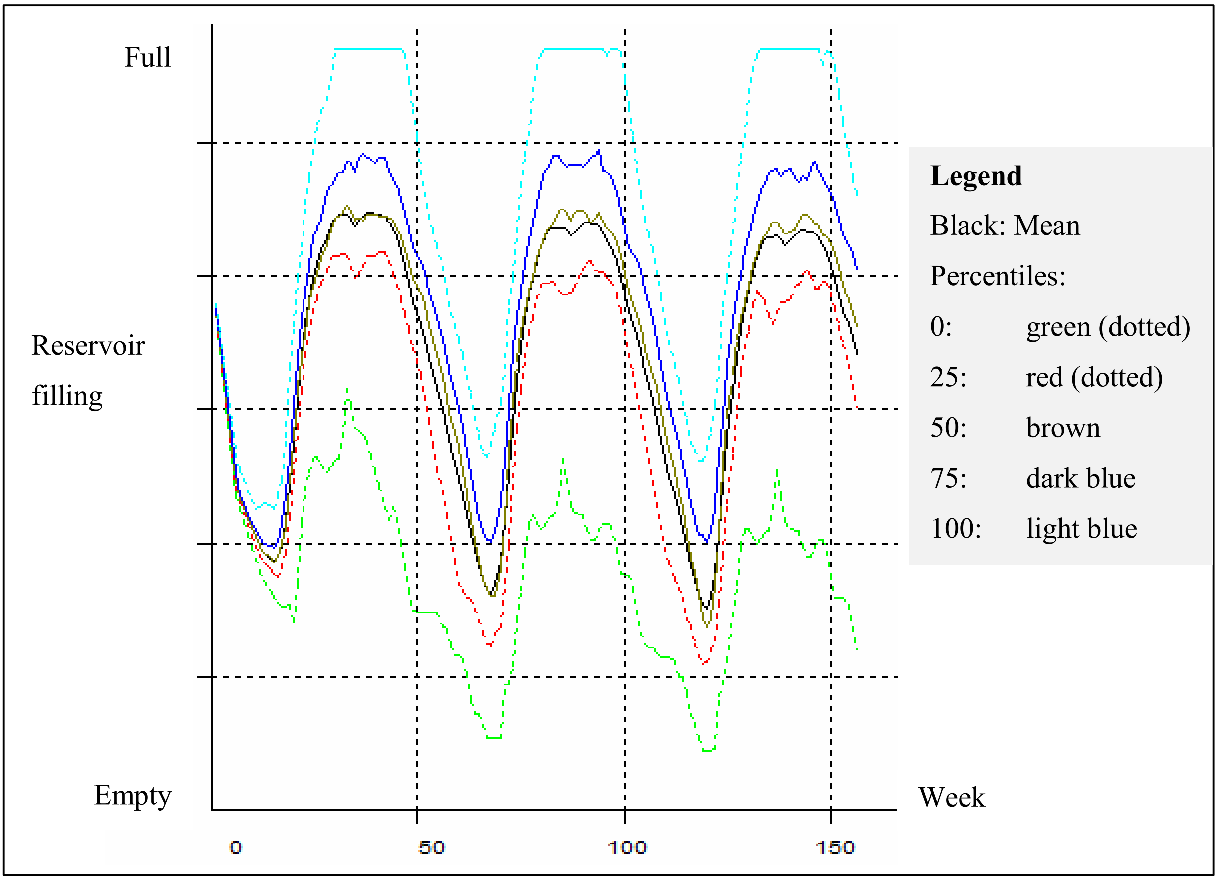

Figure 68 – Otra sum reservoir level using EMPS calibration setting "Manual 1". Base case data set.

“Automatic” calibration setup

Table 46 - Contents of file "AUTKAL_INN.CSV": Parameters for auto calibration in EMPS.

Antall hovediterasjoner	5			
Steglengde	0.1	0.1	0.1	
Prosentvis steglengde i neste hovediterasjon	0.8			
Omradenummer	Omradenavn	Tilbakekobling	Form	Elastisitet
1	NUMEDAL	4	7	1
2	TEV	5	8	2
3	OTRA	6	9	3
4	TERM	0	0	0
Omradenummer	Omradenavn	Vekting av samf.ok. overskudd		
1	NUMEDAL	1		
2	TEV	1		
3	OTRA	1		
4	TERM	1		

Table 46 holds automatically generated values. It indicates that the automatic calibration will run through five main iterations, each constituting a change in all nine calibration factors. Each factor is increased or decreased by a multiple of the step-length until socioeconomic surplus is maximized. For the first iteration, the step-length is set to 0.1; this is then decreased by a factor of 0.8 for each main iteration. The above table also sets the order in which the factors are changed - elasticity first, feedback second and shape third. Finally, the file sets equal weighing of socioeconomic surplus in each area. Below are the sum reservoir levels using the “Automatic” calibration.

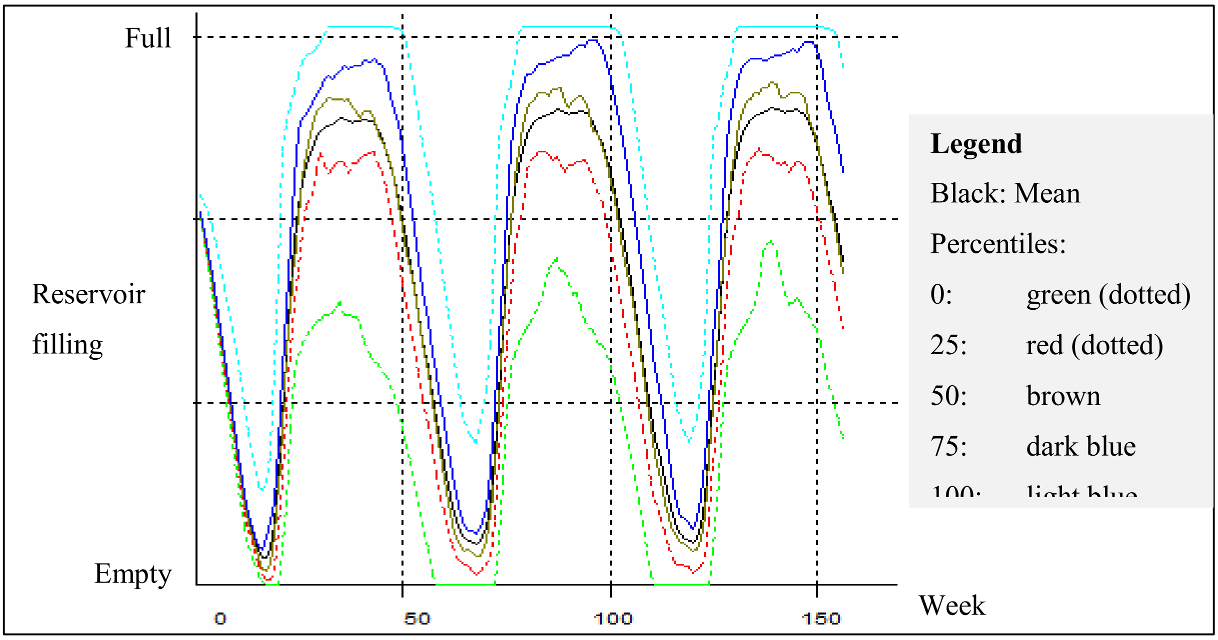

Figure 69 – Numedal sum reservoir level using EMPS calibration setting "Automatic". Base case data set.

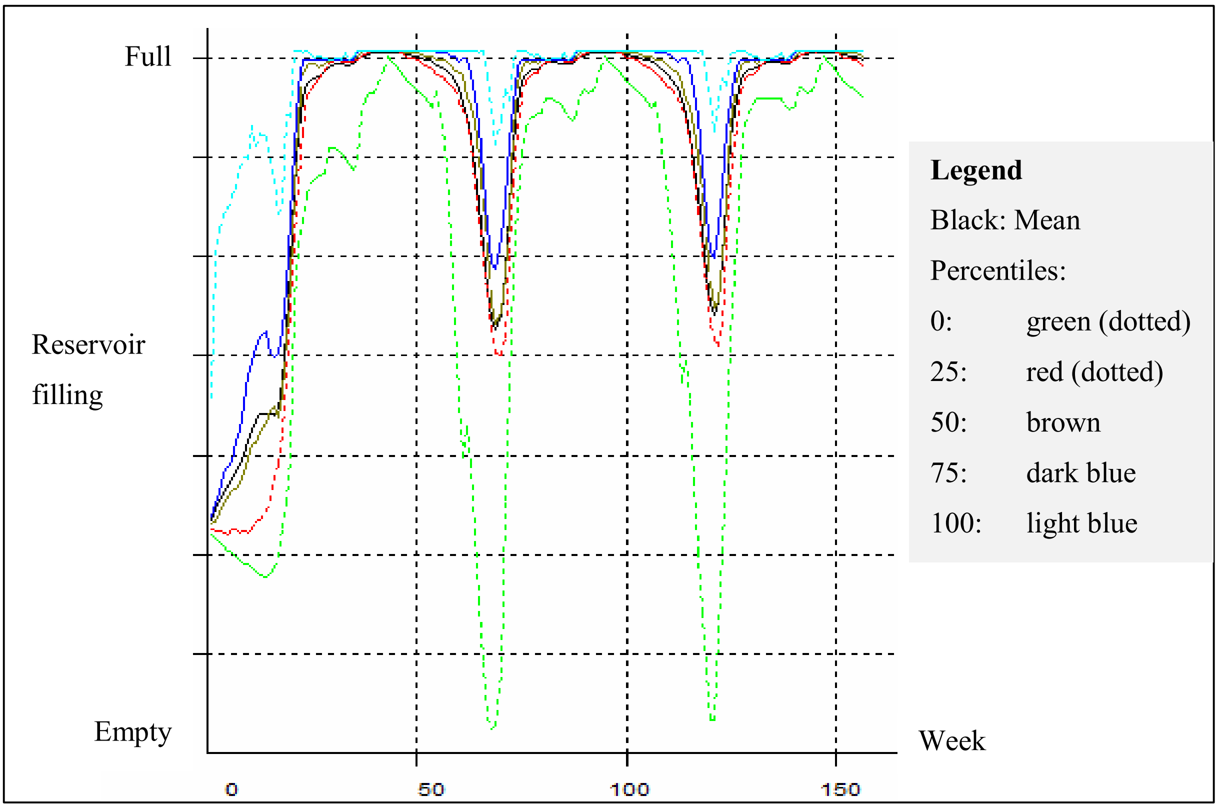

Figure 70 – TEV sum reservoir level using EMPS calibration setting "Automatic". Base case data set. This figure is identical to Figure 5.

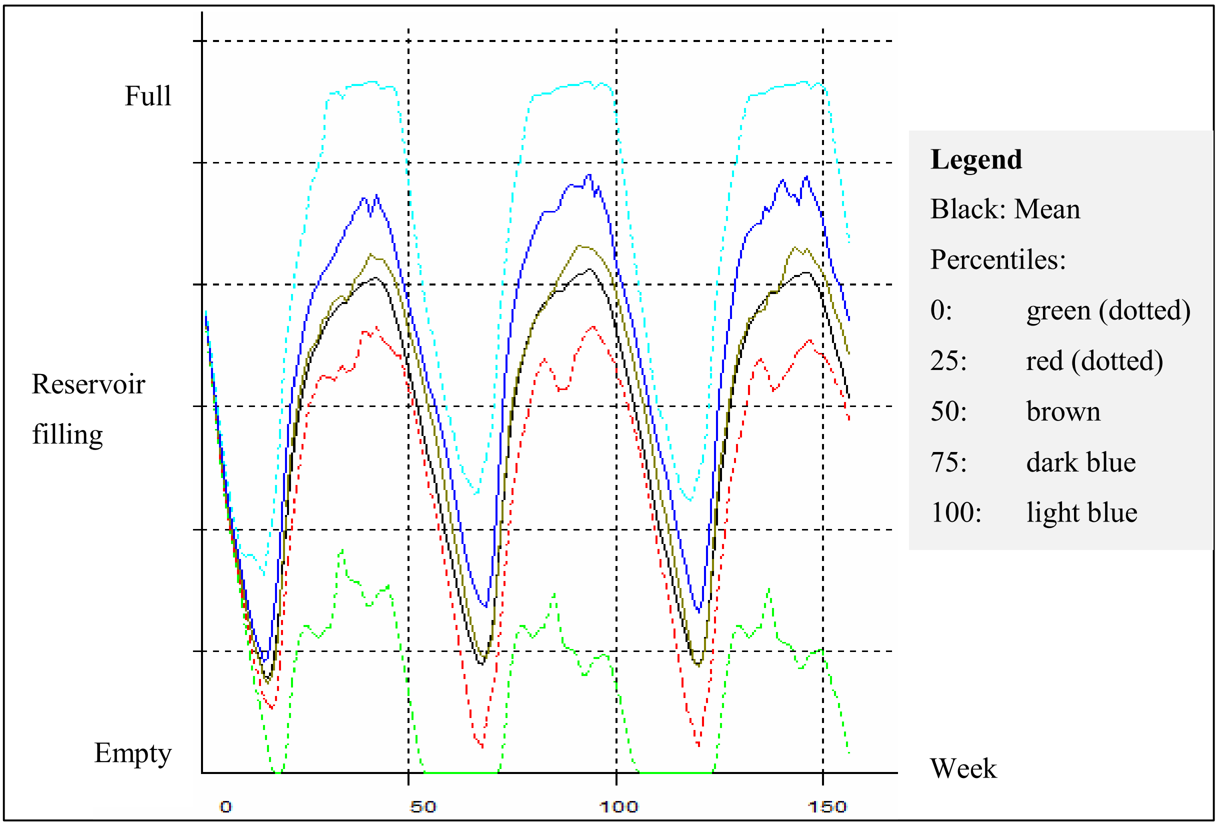

Figure 71 – Otra sum reservoir level using EMPS calibration setting "Automatic". Base case data set.

"Manual 2" calibration setup

Below follow the sum reservoir levels for each of the three hydropower areas using the "Manual 2" calibration. All simulated cases are shown. This setting was used for the three simulation cases in the thesis.

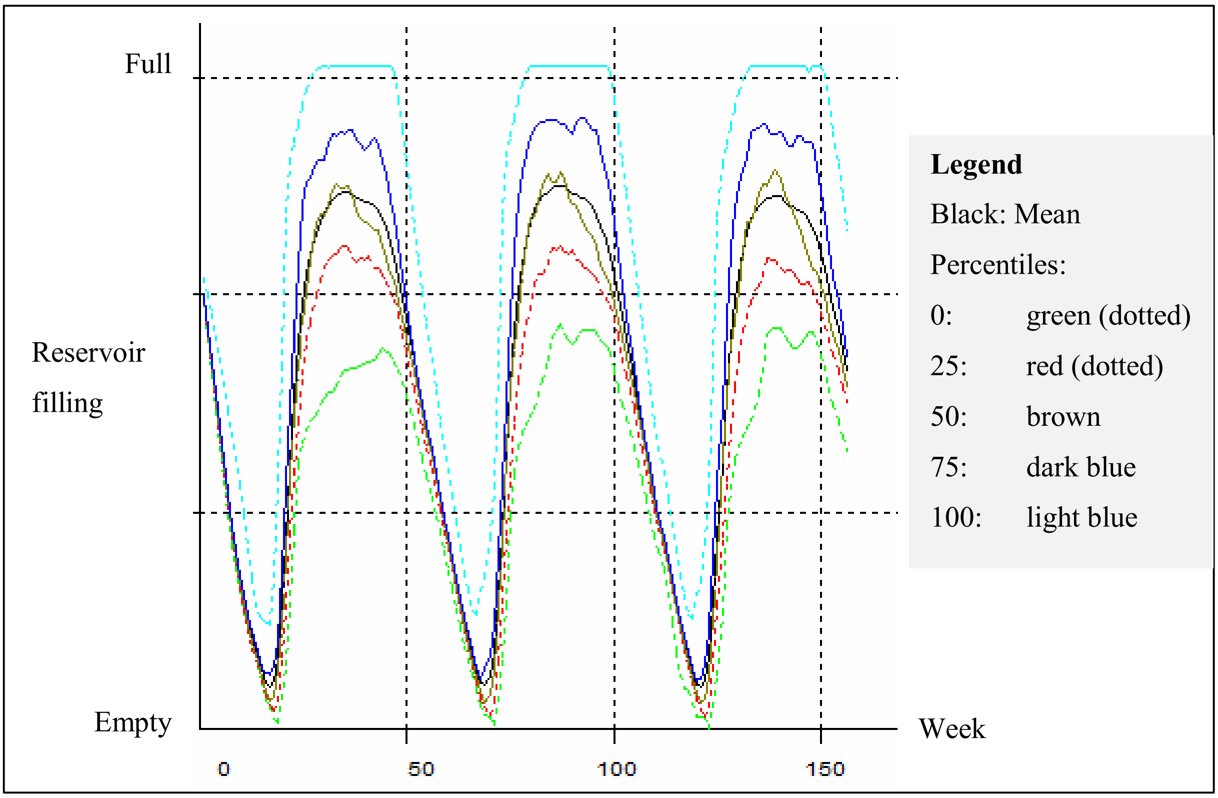

Figure 72 – Numedal sum reservoir level using EMPS calibration setting "Manual 2". Base case data set.

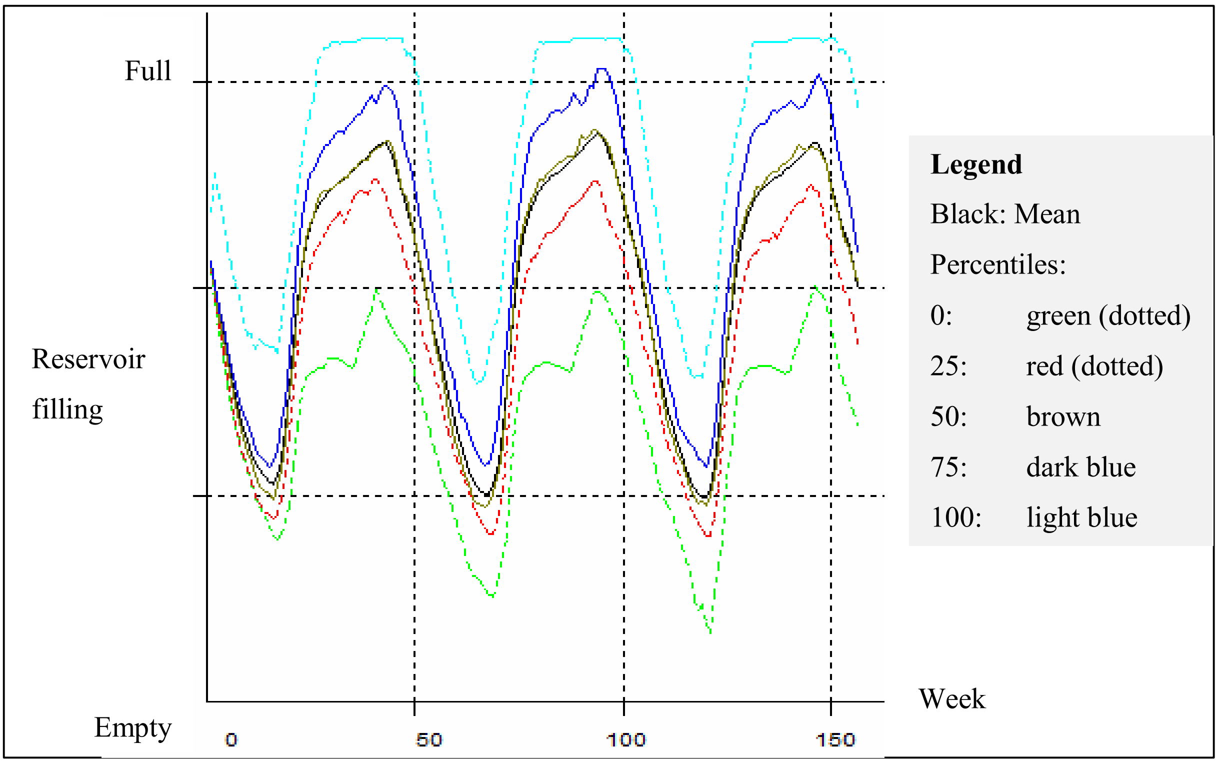

Figure 73 – TEV sum reservoir level using EMPS calibration setting "Manual 2". Base case data set.

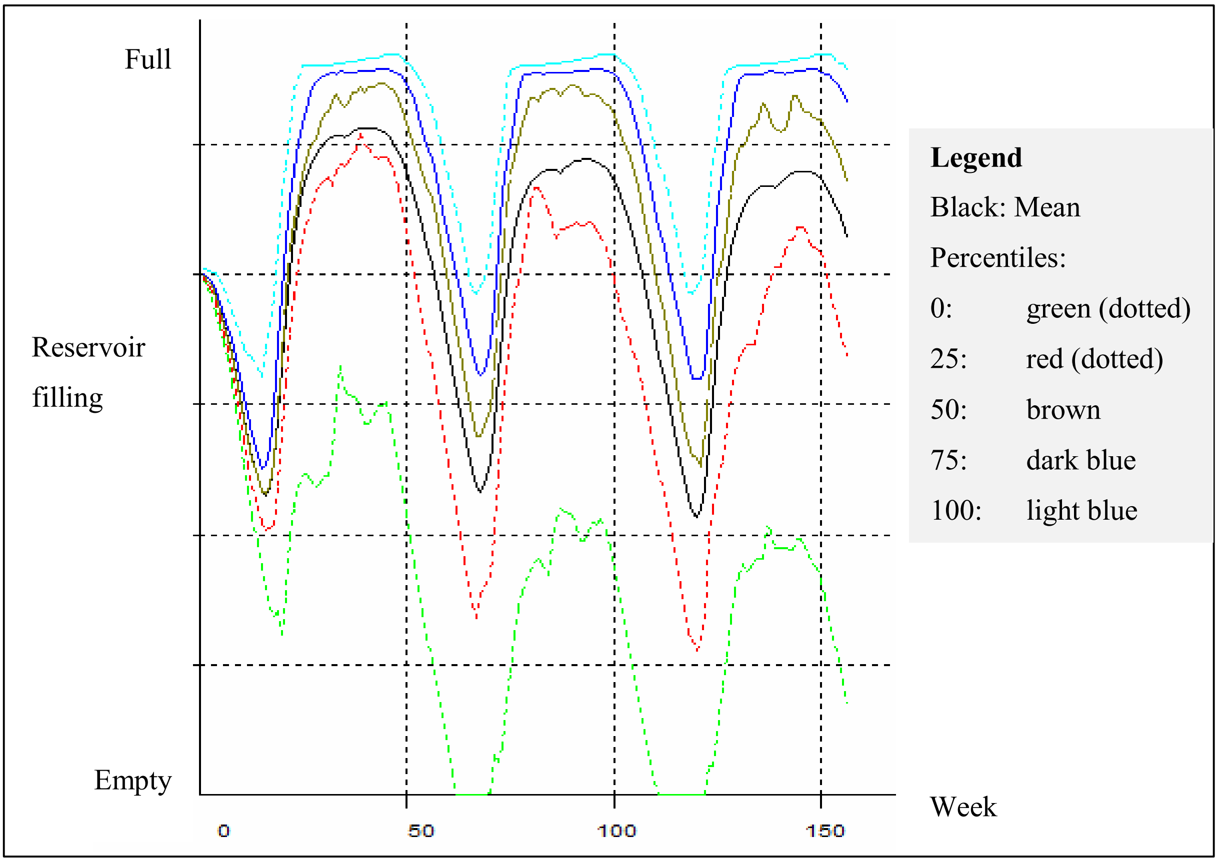

Figure 74 – Otra sum reservoir level using EMPS calibration setting "Manual 2". Base case data set.

Scenario A area magazine plots

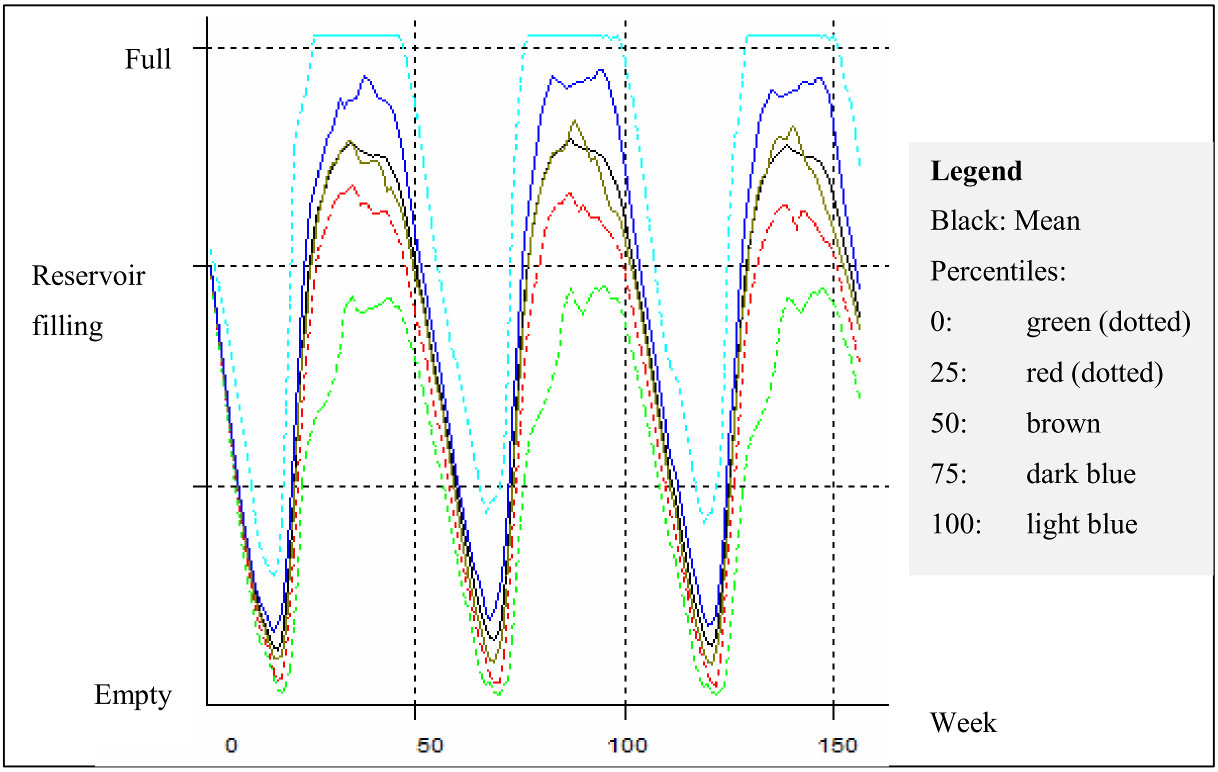

Figure 75 – Numedal sum reservoir level using EMPS calibration setting "Manual 2". Scenario A data set.

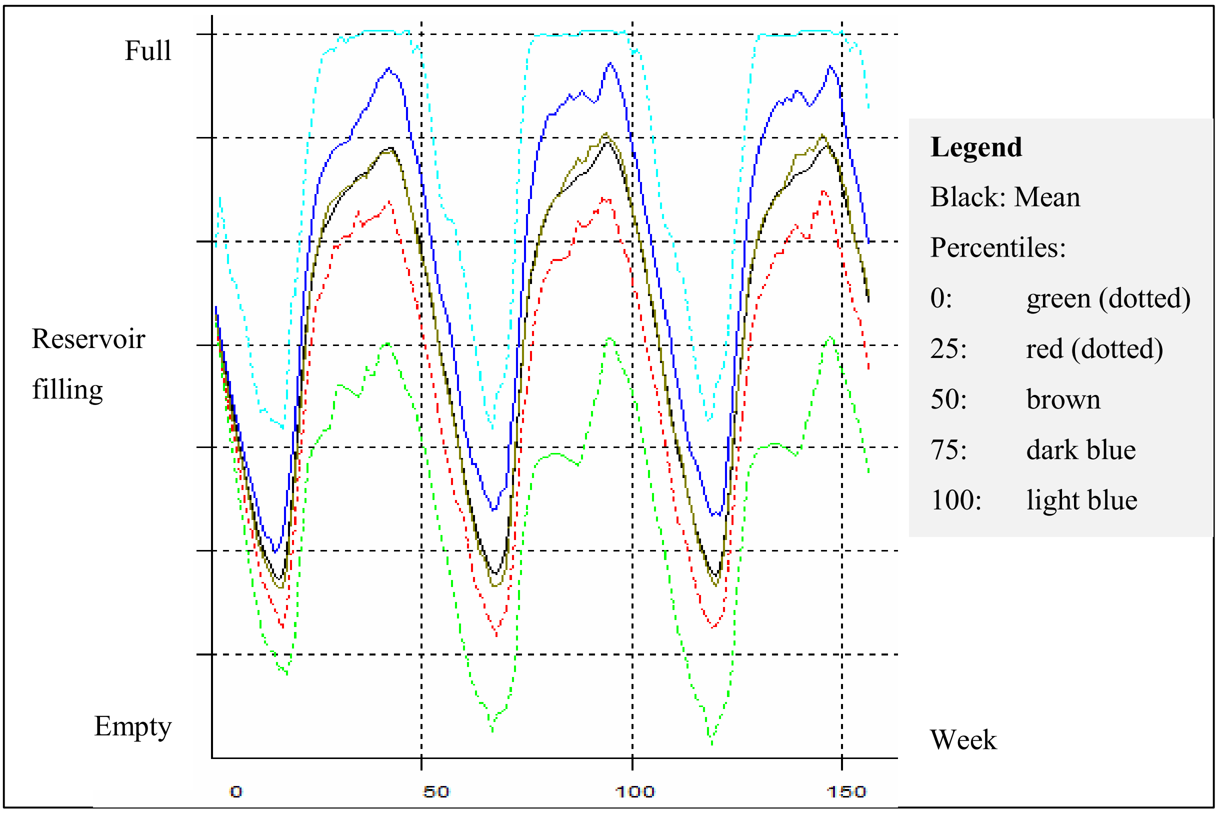

Figure 76 – TEV sum reservoir level using EMPS calibration setting "Manual 2". Scenario A data set.

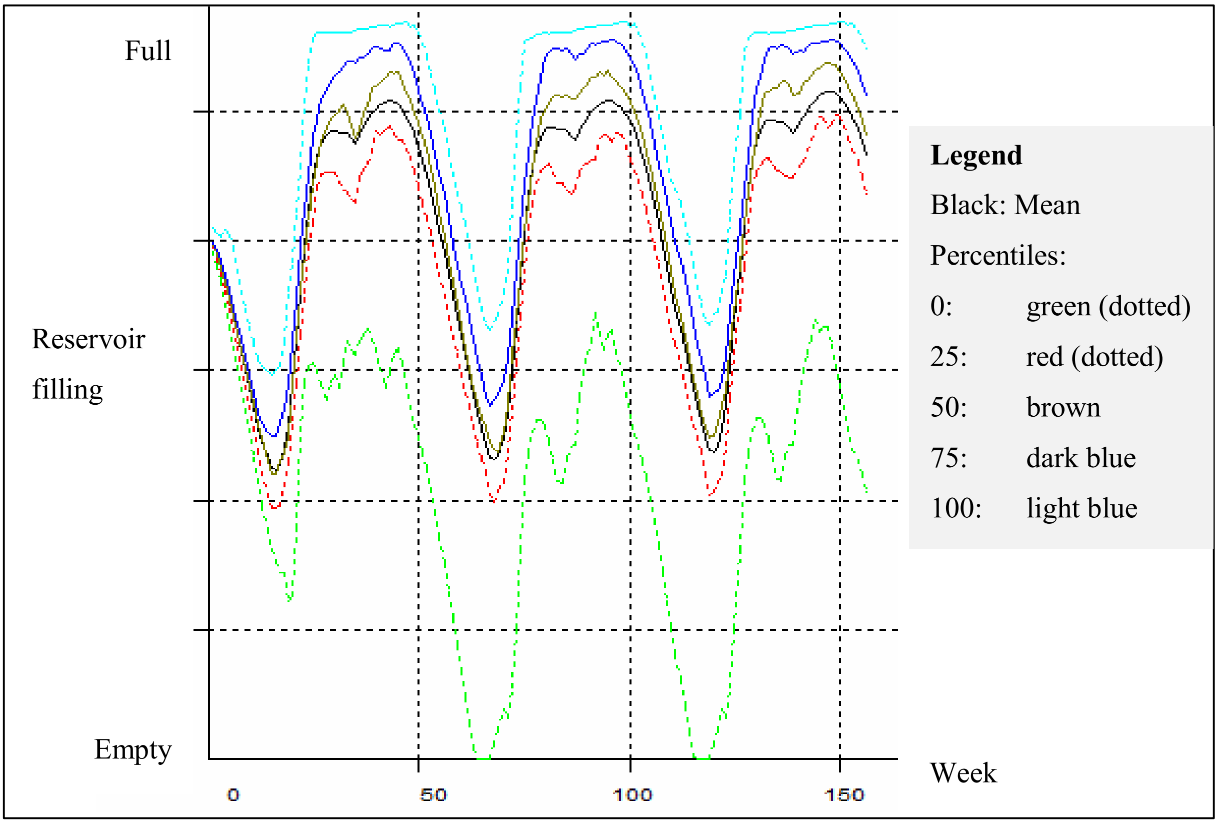

Figure 77 – Otra sum reservoir level using EMPS calibration setting "Manual 2". Scenario A data set.

Scenario B area magazine plots

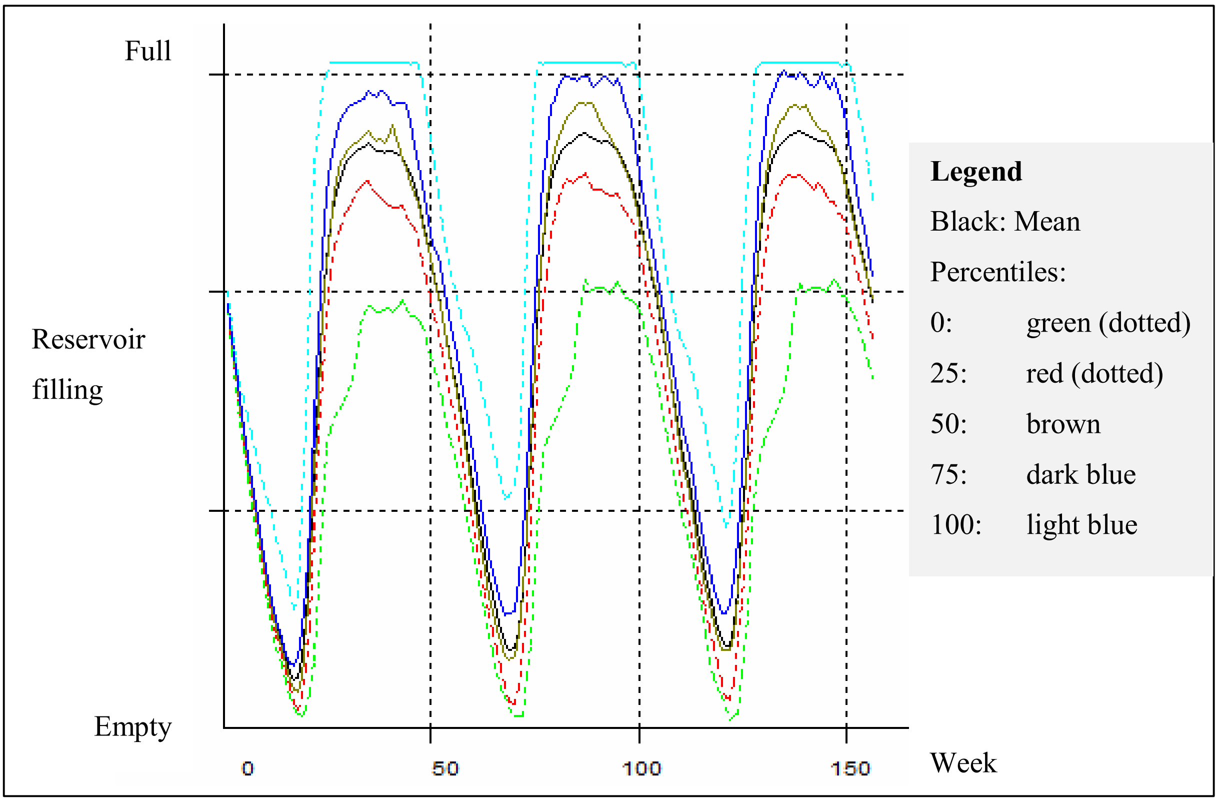

Figure 78 – Numedal sum reservoir level using EMPS calibration setting "Manual 2". Scenario B data set.

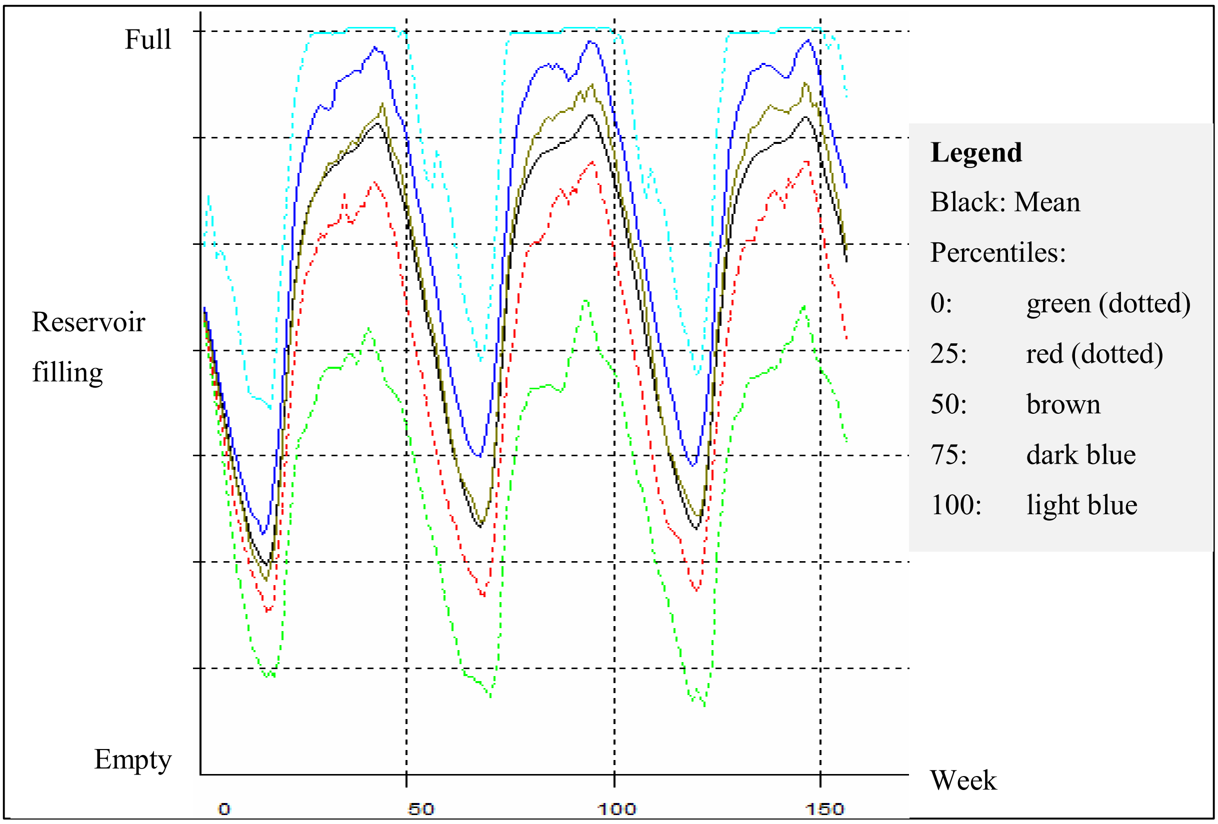

Figure 79 – TEV sum reservoir level using EMPS calibration setting "Manual 2". Scenario B data set.

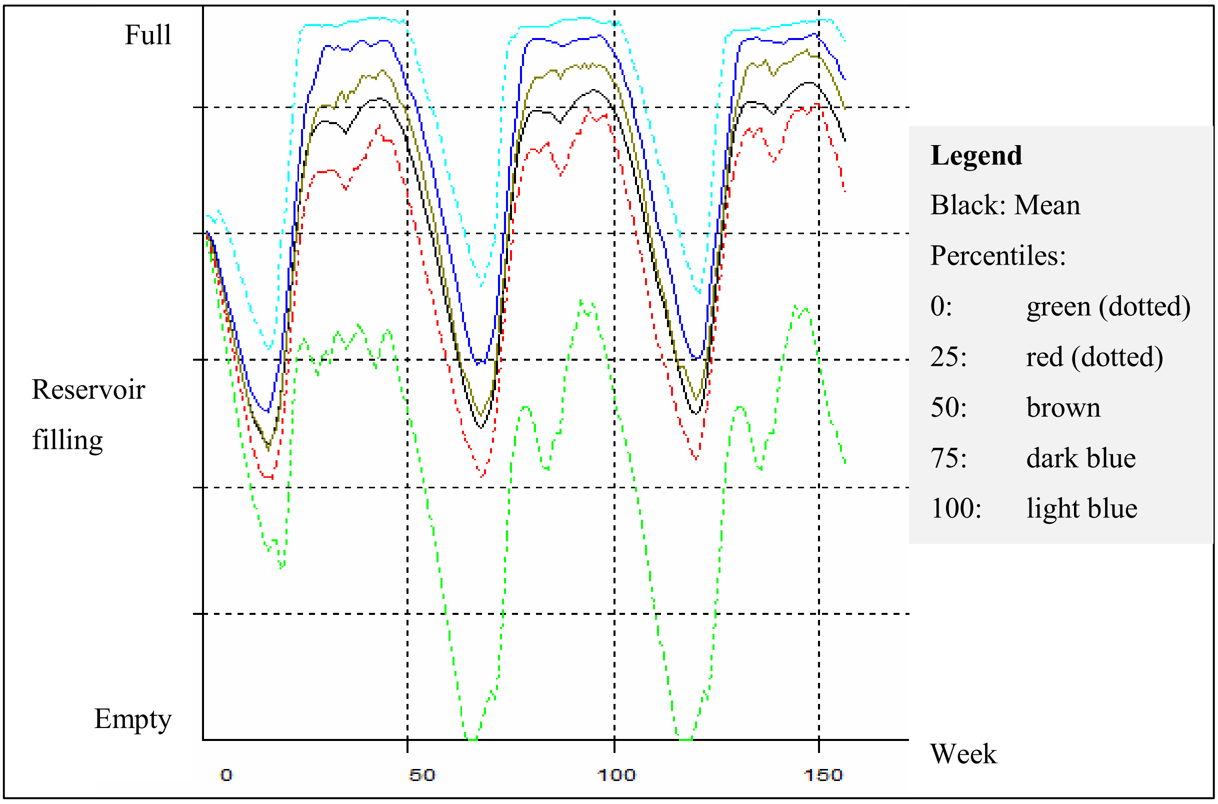

Figure 80 – Otra sum reservoir level using EMPS calibration setting "Manual 2". Scenario B data set.