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Multimarket modelling

Application of different models to HydroCen Low Emission scenario

Mari Haugen, Linn Emelie Schäffer

NTNU SINTEF NINA

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Multimarket Modelling

Documentation of price modelling using different models

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Linn Emelie Schäffer

HydroCen

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Abstract

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This report documents the work done in task 1 of WP3 in HydroCen on multimarket price modelling. The focus of the work has been to simulate spot prices and prices for procurement of reserve capacity using different modelling tools and functionality. We will in this report describe the differences between the models and functionality that have been used, compare price results and discuss challenges in this study and for future work on this topic. All the models and functionality used in this project are developed and maintained by SINTEF. The results illustrate the complexity in forecasting prices for procuring reserve capacity and the impact on spot prices. Furthermore, we find that the PriMod models provide good estimates for prices of providing reserves, while the EMPS functionality not performed that well on our test cases. The report documents nicely how SINTEFs models can be used together and highlights some important experiences to consider when conducting studies like this.

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1 Introduction

This report documents the work done in task 1 of WP3 on multimarket price modelling. The focus of the work has been to simulate spot prices and prices for procurement of reserve capacity using different modelling tools and functionality. We will in this report describe the differences between the models and functionality that have been used, compare price results, discuss challenges in the models and give some recommendations for future work on this topic. All the models and functionality used in this project are developed and maintained by SINTEF and we refer to the model documentation for further details about each model.

All simulations are done based on the same dataset, the HydroCen Low Emission scenario [1,2]. The only differences between the simulations are the models and functionality that are used and the cases for reserve requirements.

1.1 The models and functionality

The models and functionality that have been tested as part of this work are described briefly below.

1.1.1 EMPS

The EMPS is a fundamental market model for optimisation of hydro-thermal power systems. The model is well established and used by most of the large hydropower companies in the Nordic region, Nordic TSOs and the Norwegian regulator to analyse operation of the power system and potential expansions. Furthermore, the EMPS is used in research projects to analyse scenarios for development of the European and Norwegian power system [3,4,5]. The user can define the temporal resolution in the model down to an hourly resolution. In this study a 3-hour temporal resolution is used for a one-year planning horizon with a stochastic optimization for the long-term valuation of water. Simulations are done for 58 historical weather years.

Reserve functionality

The reserve capacity functionality used in this analysis is implemented as a prototype functionality. Requirements for reserve capacity are defined in the model as a minimum capacity requirement per time step. In order to provide reserve capacity, units need to be dispatched in the given time step. The user defines which price areas should be included in each group, e.g. one area per group, country wise groups etc. There are two versions of the reserve requirement functionality:

1. The first allows the user to define requirements for upwards reserves but does not report reserve prices (this is included in the commercial version of the software) [6].
2. The second version builds on the first and includes downwards reserve requirements in addition. Furthermore, the marginal reserve costs, i.e. the dual values of the reserve capacity constraints, are provided as output. The functionality and implementation are described in [7].

Two EMPS versions were used in this study, version 9 (V9.9) and version 10 (V10). The EMPSW model and the PriMod model builds on EMPS V10. Hence, running EMPS V10 was a necessary step before running simulations with these models. However, EMPS V10 only includes the standard (commercially available) reserve requirement functionality, and V9 was therefore used in this study.

In this work we have mainly used the second version as this is the only version that reports the dual of the reserve requirement constraint as an output. It is important to note that the reported dual values are the dual values of the reserve capacity constraints in a linear optimization problem where hydro is aggregated to one plant and one reservoir. The reserve capacity constraints are not included in the drawdown heuristics (detailed unit-wise dispatch of hydropower units). For all units providing reserves the sum of the reserve capacity and the capacity used to deliver in the spot market must be within the minimum and maximum production limits. The minimum production level is the lowest technical production a unit can produce at before shutting down (the units need to be spinning, i.e. running, to deliver reserves). For the aggregated hydropower model, there is a defined minimum level for aggregated production for the entire area based on the individual plant descriptions for a given time step and weather scenario. In addition to the sum of the physical minimum unit productions, the aggregated minimum production for the area is given by minimum discharge constraints and non-controllable hydro production.

If the reserve requirement cannot be obeyed, the model has an option to buy expensive reserve capacity through a penalty variable (for robustness). This cost is set to 2999 EUR/MW/h, just below the rationing cost in the dataset.

1.1.2 EMPSW

The EMPSW model builds on the EMPS, the main difference being that hydro is represented with all modelled details in a formal optimization for the weekly market clearing. There is no iteration between aggregated hydro model and the detailed representation in market clearing part of the model. This improve considerably the model's utilization of short-term flexibility in complex serial water courses. The long-term valuation of water (the strategy) from EMPS is used to specify the value of water by the end of each week. The same temporal resolution as in the EMPS is used (3-hour). Simulations are done for the same number of historical weather years as in EMPS. To ensure the best possible basis for comparison between the models, the initial reservoirs for each year in EMPSW are obtained from the EMPS results. This guarantees that the starting point for simulated weather years is the same between the models. EMPSW is described in [8].

The EMPSW was run with constraints on cable ramping (same as in PriMod) and start-up costs on thermal power plants.

Reserve functionality

EMPSW has functionality for reservation of upward and downward reserve capacity. The implementation is similar to the original reserve capacity functionality in EMPS V9 but includes also procurement of downwards reserve capacity. Reserve requirements can be defined by the user either for individual areas or for groups of areas. The reserve capacity per area/group is assumed to be symmetric, meaning that the capacity demand for upward and downward reserves is the same. In EMPSW, all hydropower units with production capacity and initial reservoirs larger or equal to 1.0 Mm^3 can contribute with reserve capacity. The hydropower units do not have to run to provide upward reserve capacity (spinning reserves). Maximum upward reserve capacity allocated on each individual hydropower unit is limited to the difference between the maximum production and the actual production of the unit. The modelling is the same as described for the SOVN/Fansi model [9]. Maximum downward capacity reserved on each individual power plant is limited by the production above the minimum production defined by the minimum discharge requirement.

The dual value of the reserve requirements constraint is not provided as an output in the EMPSW model, and hence only the spot prices are analysed.

1.1.3 PriMod

The PriMod model is a fundamental multi-market model with detailed representation of hydropower [10]. The model has a 15 min time resolution, minimum production and start-up costs on hydropower modules, detailed thermal modelling with start-up costs, minimum production, ramping, minimum up- and downtime [11], ramping on HVDC cables and constraints for reserve requirements per defined group of areas for up and down spinning reserve capacity. There is a simultaneous clearing of the spot market and reserve capacity market. PriMod re-optimizes the weekly dispatch decision problem with boundary conditions from a long-term model. This is done by optimizing one day at a time, with a linear interpolation in the individual water values from EMPSW (or cuts from FanSi) from the end of the previous week (water values at the start of the week) and the end of the current week (water values at the end of the week) as end valuation of hydro resources. In our calculations all binary variables in the model are relaxed, making it a linear problem.

In this work, all hydropower plants with maximum reservoir capacity of 1 Mm^3 or higher can deliver reserve capacity. The effects of delivering balancing energy are not considered in the model (e.g. that there is available water in the reservoirs to regulate up the production). The start-up cost for each hydropower module is estimated by a linear function of maximum production capacity, p: Start-up cost = 100 + 0.2p EUR. Minimum production is estimated from the production-discharge curve (PQ-curve) for each module, where the minimum production is set to 50 % of the best efficiency point. The maximum production is the sum of the production on each segment on the plants PQ-curve modified by the relative head. The relative head is updated for each day. Each module must be spinning to deliver reserve capacity. The maximum available capacity for upward regulation is the difference between maximum production and actual production, and the maximum available downward capacity is the difference between actual production and minimum production. The same applies to thermal plants. Since all binary variables are relaxed, units can be committed below minimum production. Then these start-up variables will be between 0 and 1, and the minimum production and maximum production is modified according to the fraction the unit is committed. The available reserve capacity upward and downward therefore also decreases. If a hydropower unit that is half-committed also is a marginal unit for upward and downward reserve capacity, delivering one more unit of upward or downward capacity can be done by increasing the start-up variable, and hence the maximum production and minimum production, and then adjust the production. The sum of the upward reserve capacity procured at each hydropower module and thermal plants in each reserve group must meet the upward capacity requirement for that reserve area. The same applies for downward reserve capacity. If exchange of reserves between areas is allowed, the reserve group can import reserve capacity from other reserve groups by reserving capacity on the transmission lines. Upward capacity can be delivered from group A to B up to the difference between maximum capacity from A to B and the spot flow from A to B. Downward capacity from A to B can be delivered up to the difference between maximum capacity from B to A and the spot flow from B to A. A group can import reserve capacity from one group and export reserve capacity to another group. If the reserve requirement cannot be obeyed, the model has an option to buy expensive reserve capacity (for robustness). This cost is set to 2999 EUR/MW, just below the rationing cost in the dataset.

PriMod have many similarities to EMPSW but the time resolution is higher, modelling detail is greater, and more types of constraints are implemented. Therefore, computation time is longer and PriMod is typically used to solve a few representative weeks and not the continues sequence of weeks and weather years as EMPSW is designed for.

1.2 Description of the simulations

In this study we analyse several cases using different models and functionality, described further in section 1.2.1. The analyses discussed in this report are based on results from three simulation (weather) years for the defined cases. The years are selected based on inflow characteristics and represent a year with low inflow, high inflow and normal inflow respectively. Four weeks from these simulation years are selected for further analyses using the PriMod model. The main discussion of the results will focus on simulated prices for these weeks. The weeks were selected to represent different conditions of the system. The simulated spot price from the EMPS model was used to identify appropriate weeks. In year 1960, the dry year, a winter week with high power prices and low inflow? was selected. In the wet year, 1989, a summer week with low power prices and high inflow was chosen. In the normal year, 2009, a spring week with low price and an early winter week with higher power prices were chosen. The selected years and weeks are given in Table 1.

Table 1 The selected weather years and weeks analysed in this study

Year	Inflow	Week numbers
1960	Low	3
1989	High	31
2009	Normal	21 and 50

1.2.1 Test cases

The assumptions for reserve requirements are based on today's requirements and suggestions from Statnett. The modelled reserve requirements are spinning so we aim at modelling primary (FCR-N and FCR-D) and secondary (aFRR) reserves. We assume that the demand for secondary reserves will double from 300 MW to 600 MW for the Nordic regions by 2030. An estimate of how this demand can be distributed on price areas was provided by Statnett. We used the same allocation key for dividing primary reserves within each country. The demand for primary reserves was assumed to be unchanged from today to 2030; 600 MW in total for FCR-N (symmetric) and 1200 MW FCR-D up. The distribution of demand for primary reserves per country was taken from [12]. As a consequence of more interconnectors to exogenous markets by 2030, we chose to add a requirement for 1200 MW FCR-D down in addition to FCR-N. This product does not exist today but will probably be implemented when the new interconnectors to Germany and Great Britain come into operation. In addition, this was also necessary from a modelling perspective, as the EMPSW model only accept symmetric reserve requirements for up and down capacity. The models used in this study do not differ between primary and secondary reserves, so the requirements (aFRR + FCR-N + FCR-D) were merged into one common requirement per country and price area (see Table 2) in the modelling.

Table 2 Reserve requirements for upward and downward capacity (symmetrical reserve capacity requirements) per country and elspot area.

Country	Total reserve requirement up/down (MW)	Price areas	Total reserve requirement up/down (MW)
Norway	791	NO1	167
		NO2	229
		NO3	83
		NO4	146
		NO5	167
Sweden	924	SE1	216
		SE2	157
		SE3	354
		SE4	197
Finland	335	FIN	335
Denmark	356	DK2	356
TOTAL	**2406**		**2406**

The analysis comprises four different cases for reserve requirements: no reserve requirements in the base case, reserve requirements per country in the country case and reserve requirements per price area in the area and area exchange case. The area exchange case includes in addition the possibility of reserving capacity on the grid to exchange reserve capacity between price areas. Not all cases could be run with all models because of the functionality required (see Table 3).

Table 3 Four different cases were studied

Case	Explanation	EMPS V9	EMPS V10	EMPSW	PriMod
Base	No reserve capacity	x		x	x
Country	Reserve capacity per country	x	x	x	x
Area	Reserve capacity per price area	x		x	x
Area ex	Reserve capacity per price area with possibility to exchange reserves				x

1.2.2 Model simulations/runs

Some of the models take results from other models as input in the simulations. Because of this, the models have been run in series, as illustrated in Figure 1. This figure also gives an overview of what models, model functionality and cases that were run on the dataset and are mentioned in this report. In general, the EMPSW require aggregated water values (an aggregated strategy) from EMPS as input, while PriMod requires an end-value setting for the end of the week and reservoir levels at the start of the week for each reservoir, here these values was provided by EMPSW. The figure shows that the dataset, after simulation by EMPS V9 base case, was upgraded to an EMPS V10 dataset and simulated by EMPS V10 with country based reserve areas. This formed the basis for the dataset used further on with EMPSW and the cases with different initial reservoirs.

EMPSW was run in parallel simulation model for all the weather years, and the dataset was updated with initial reservoirs corresponding to the years 1960, 1989 and 2009 in advance. These initial reservoirs were obtained from the series simulation in EMPS V9. For 1960 and 1989, the reservoir levels (percentage filling per area) from a simulation with EMPS V9 and reserve requirements per country were used. In this model run, the penalty for not meeting the reserve capacity requirements were 70 EUR/MW. The initial reservoirs for 2009 was also obtained from a simulation done with EMPS V9 and reserve requirements per country, but with the aforementioned penalty set to 2999 EUR/MW.

The end of week value of water and initial reservoirs used in PriMod come from the EMPSW results for the country case, except for inflow year 2009 where the values come from the corresponding EMPSW case. As there is no area exchange case in EMPSW, the area exchange case in Primod used the EMPSW water values and reservoirs from the area case.

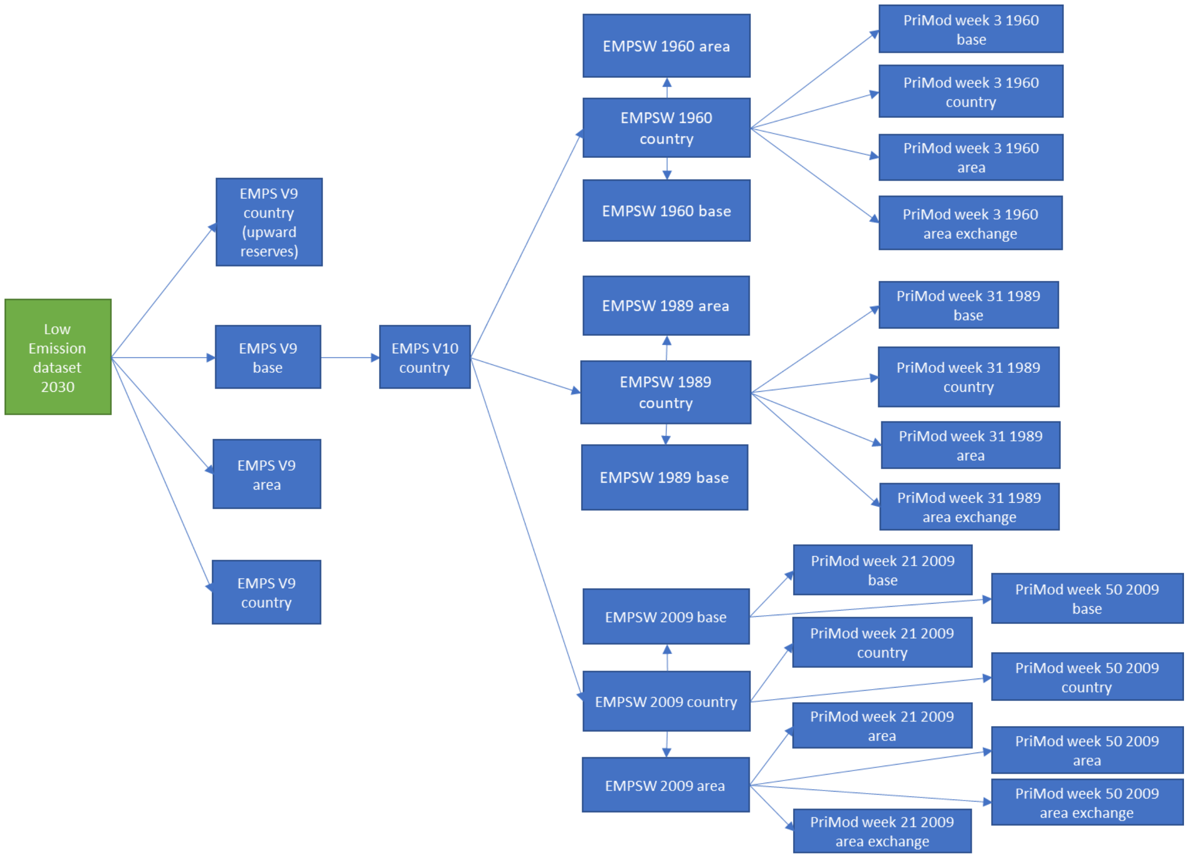

Figure 1 Illustration of what models, model functionality and cases that were run on the dataset, and the relationship between them.

1.2.3 Type of results

This report compares spot prices and the prices of procuring reserves between the described models and cases. The type of prices that can be provided the different models varies. Table 4 gives an overview of the three types of prices that are reported and which models that provide the different output. Two of the models give the dual value of the reserve constraint as an output. However, this value cannot be taken directly as the price of procuring reserve capacity. This is related to how the constraints for procuring reserves are implemented and is explained further later in the report (ref?).

All the results presented in this report are for the Ostland region (NO1).

Table 4 The three types of prices studied.

Legend	Explanation	V9	V10	EMPSW	PriMod
Spot	Dual of power balance, spot price	x	x	x	x
Res up	Dual of reserve capacity constraint for upwards reserve requirement	x			x
Res down	Dual of reserve capacity constraint for downwards reserve requirement	x			x

1.3 Price effects of including reserve capacity requirements

This section describes some general characteristics and principles for price calculation.

The models used in this study optimizes the spot market and the reserve capacity market simultaneously. In a case with no reserves, all plants with marginal cost/water value below the spot price produces at optimum and the marginal unit sets the price. This is not necessary the case when reserve requirements are added, because the model minimizes the cost of covering demand and providing reserve capacity simultaneously.

In a linear problem, the dual of the market balance constraint will equal the marginal cost of requiring one more unit of energy and the dual of the reserve requirement constraint will equal the marginal cost of procuring one more unit of reserve capacity. In a perfect market solution, the marginal cost of a resource will set the price of that resource. Normally, the dual of a constraint therefore represents the price of the resource limited by the constraint. In this report we use the terms "reserve price" and "dual value" interchangeably.

In general, a problem that is more restricted has equal or higher costs than a problem with less constraints. Still, the impact on the spot price from including reserve capacity constraints can give both higher and lower spot prices. When there is no cost of reserving capacity, the reserve requirement will have little effect on the spot price, but if there is a cost of procuring reserves in a time step there will likely be an impact on the spot price. Furthermore, requiring reserves can give a different use of water. Since the problem is dynamic, this can give a deviation in the reservoir filling over time and have an impact on the spot price also in following time steps.

Prices for reserving capacity occur when the optimal solution for covering the demand must be altered to be able to also fulfil the reserve capacity requirements. Available free capacity in the system is not enough to cover the reserve demand, so a less optimal solution must be used to cover demand to be able to also cover the reserve requirements. To provide upwards reserve capacity, some generation capacity will be held back to ensure that there is enough generation capacity that can ramp up if something unexpected happens. This means that there is less generation capacity available to produce under "normal conditions" and the cost of meeting demand can increase in hours with high demand. This can lead to a higher spot price. In hours with low demand, regulated hydropower production can be forced to produce to fulfil the demand for upward spinning reserve capacity. This can then lead to a lower spot price. Many hydropower plants have an optimal production point below maximum production. It is therefore often a lot of free upwards reserve capacity in hydropower dominated areas, as these units can provide upwards reserves without altering the optimal solution for covering demand.

To provide downwards reserves, some generation capacity commit to produce to ensure that there is generation capacity that can ramp down production if something unexpected happens. There will not be a price for providing downwards reserves as long as there is enough "naturally provided reserves" by regulated production units dispatched to cover demand. If this is not the case, units can be forced to produce to ensure that the reserve capacity requirement is met. This means that there can be situations where generation capacity ends up producing at a lower spot price than they normally would. In this situation, the spot price can be lower than when reserve capacity is not included because cheaper production alternatives than the ones producing to provide downwards reserves are forced out of the market. Such a situation can occur when there is a surplus of unregulated production in the system and the spot price goes to zero. Regulated hydropower production will only produce to fulfil the minimum requirements for bypass and discharge. When requirements for upward and downward capacity are added, this can force regulated hydropower plants to produce more, and the alternative cost of the used water will set the price of providing downwards reserves.

2 EMPS (V9)

The EMPS has been used for simulations with and without requirements for reserve capacity. The first step was to simulate spot prices using the EMPS without including requirements for reserve capacity. Results from this simulation is presented in section 2.1.1. The second step was to include requirements for reserve capacity in the simulations. Section 2.1.2 compare spot price results from simulations using the different reserve requirements functionality versions. Section 2.1.3 compare spot price results given different levels of reserve capacity requirements. Finally, resulting spot prices and reserve duals from the country and area reserve requirement cases are presented in section 2.2.

2.1 Spot prices

This section presents and compare spot price results from the different simulations.

2.1.1 Without reserve capacity requirements

The EMPS was first solved without procurement of reserve capacity. The spot price from this simulation has been used as a base case when comparing results from other cases. Figure 2 shows the simulated spot price for three different weather years. 1960 is a dry year and the general spot price level is therefore higher than for the other years. 1989 represent a wet year and the price level is lower, especially in the summer period where non-controllable production from hydro, wind and solar is larger than demand. Normally, the price variation between two consecutive time steps are small, because of the flexibility given by the large hydro storages. When the system is stressed, winter period in dry years or summer period with high inflows the short-term variation increases significantly.

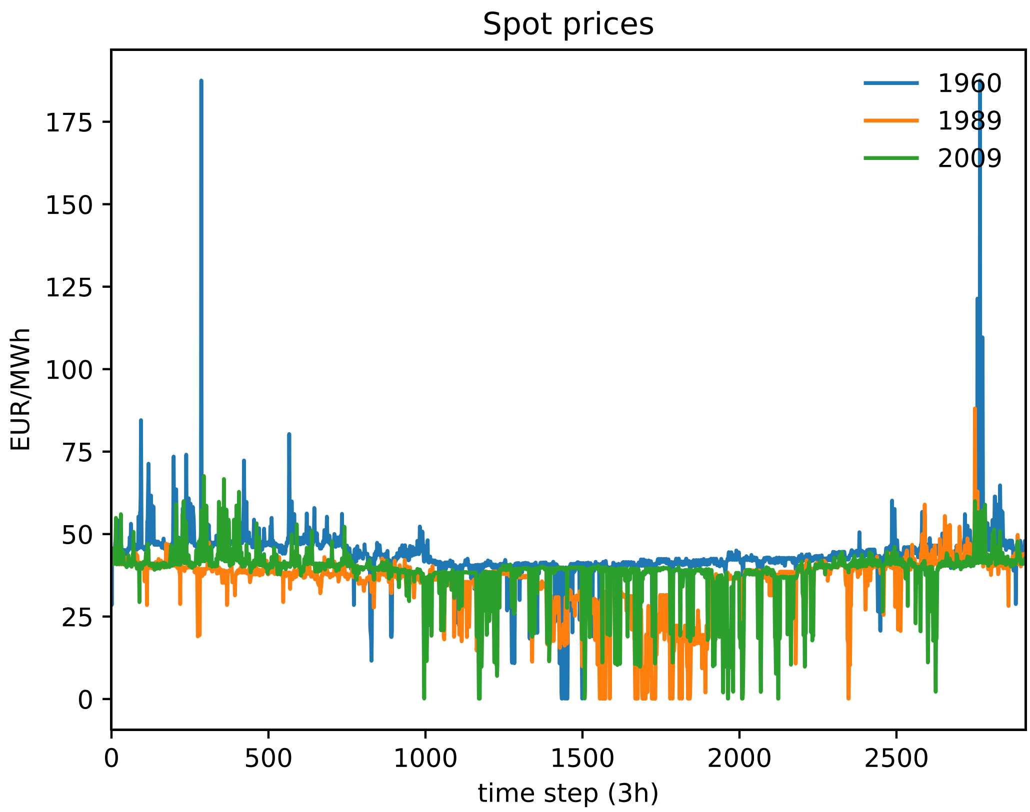

Figure 2. Plot of the simulated spot price for three weather years using the EMPS model. No reserves requirements are included. Prices are for model area OSTLAND simulated with three hour time resolution.

2.1.2 Comparison of functionality for reserve capacity

This section compares the resulting spot price from solving the EMPS without functionality for reserve requirements, with functionality for upwards reserve requirements and with functionality for upwards and downwards reserve requirements. The case with national reserve markets has been used to define reserve requirements. The same reserve requirements are used for procurement of up and downward reserves (symmetrical).

Of the two reserve requirement functionality versions, only one provide the dual of the reserve requirement constraint (the price of procuring reserves) as an output. The older version does not give prices of procuring reserves, but if there is a cost of procuring reserves, this should have an impact on the spot price. Furthermore, the EMPS model is a combination of formal optimization and heuristics, and small changes can give different outcomes from the heuristics. Figure 3 shows the simulated spot prices in the three different runs for weather year 2009. We only see some small changes in the spot prices between the simulations. In most time steps the prices are equal, but there are some differences in the peak hours.

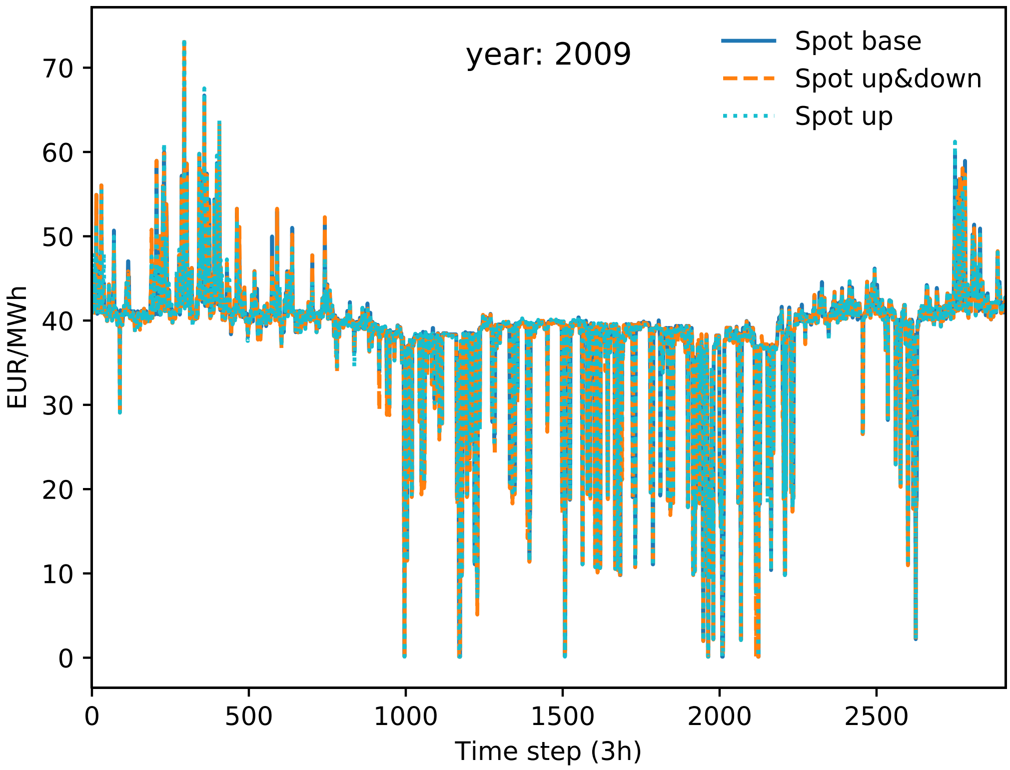

Figure 3. Simulated spot prices for weather year 2009 using the EMPS (Spot base), the EMPS with upwards reserves (Spot up) and the EMPS with upwards and downwards reserves (Spot up&down). Reserve requirement case: country.

Figure 4 shows the same plots for the four selected focus weeks. There are some differences in the peak prices, and it varies from time step to time step which solution that have the highest and lowest prices. The model simulates the weather years in a series, where the end filling in the reservoir in one year is used as the start filling of the reservoirs in the following year. A change in the input, such as reserve capacity requirements, can give a different priority for use of water and this can give an accumulated change in reservoir filing over time. In such a case, the differences between the solutions would increase over time, meaning that the results will differ more in the last simulated years (simulations run from 1958 to 2015). Figure 4 gives results from three different years, where 1989 and 2009 are quite "late" in the simulation period. Still, we see that the prices are very similar, and the price level is the same in all three simulations. This implies that the same or similar strategy for use of water is optimal in the three solutions. In other words, including upwards or upwards and downwards reserves does not change the optimal long-term use of water for this case.

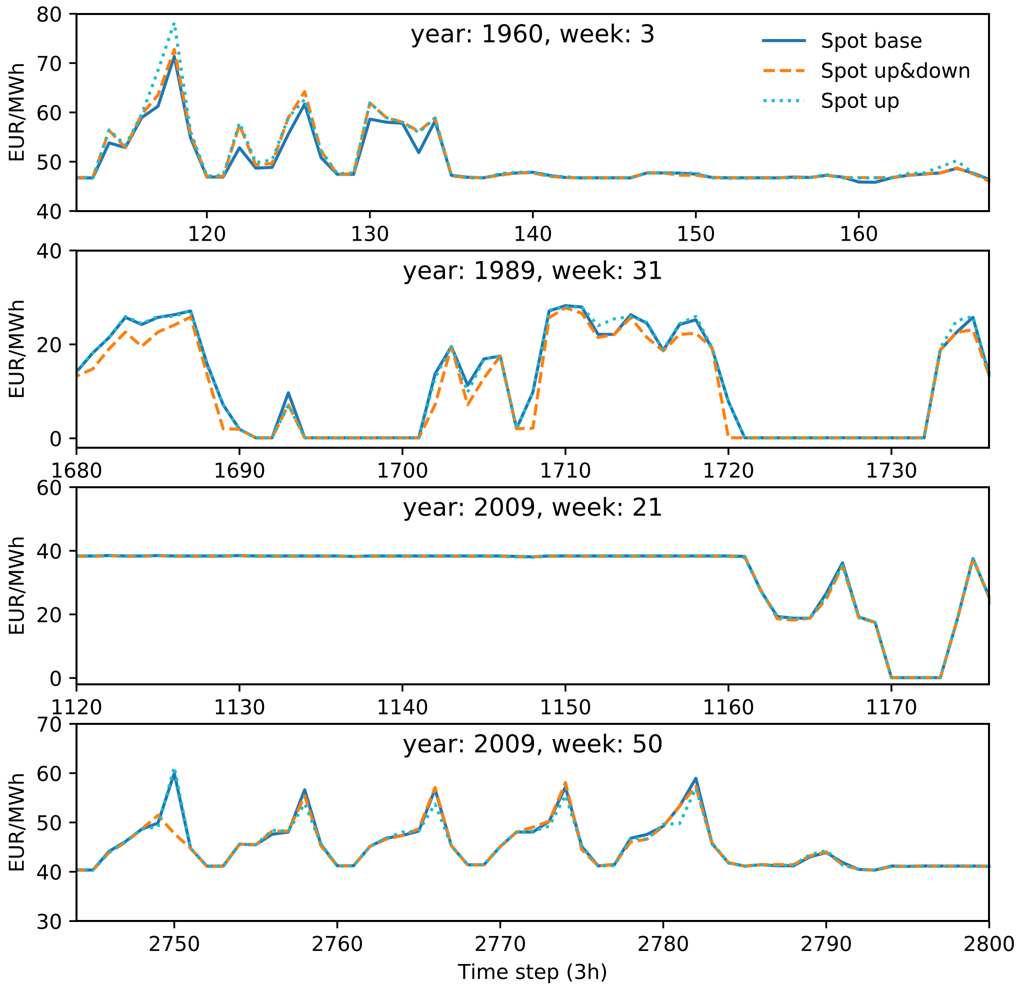

Figure 4. Simulated spot prices for week 3 in year 1960, week 31 in year 1989 and week 21 and 50 in year 2009. The prices are simulated using the EMPS (Spot base), the EMPS with upwards reserves (Spot up) and the EMPS with upwards and downwards reserves (Spot up&down). (Hva er det man bør ta med seg fra denne figure?)

2.1.3 Impact of reserve capacity requirements

In this section we compare the spot price given different levels of reserve capacity requirements. Functionality for including upwards and downwards reserve capacity requirements have been used in the simulations for the two test cases: National reserve market country and reserve price per spot area. The average spot prices in Ostland for the selected simulation years are given in Table 5. For all three simulation years the average spot price in Ostland is lower when reserve capacity is included. The average price is lowest when the reserve capacity requirements are defined per area. It is the same trend for the average price over all simulated years. One consequence of having reserve requirements defined per area is that hydropower plants that originally is not producing may have to start up to deliver reserves within that area. To deliver reserves the plants also have to produce electricity, which may reduce import into the area and push out cheaper alternatives in neighbouring areas from the production mix. Since the spot price is set by the cost of increasing production with one unit the spot price is therefore reduced. However, it is important to remember that the new solution (with reserves) is less efficient and even though the spot price is reduced in some areas, the overall system costs increase. Table 6 give the average price in Ostland for the four selected focus weeks. When considering only one and one week it varies which case that has the highest and lowest average spot price. Figure 5 shows one year of simulated spot price in the base case and the two reserve capacity requirements cases. In most hours the price is equal, but we can see some differences in some of the peak hours. It varies which case that has the highest and lowest prices.

Table 5. Average spot price in Ostland in three selected simulation years and for all years for the spot, country and area cases.

	Spot base [EUR/MWh]	**Spot country** [EUR/MWh]	**Spot area** [EUR/MWh]
1960	43.41	43.24	43.21
1989	35.36	34.93	34.90
2009	38.38	38.23	38.15
All years	40.07	39.94	39.87

Table 6. Average spot price in Ostland in four selected weeks for the spot, country and area cases.

	Spot base [EUR/MWh]	**Spot country** [EUR/MWh]	**Spot area** [EUR/MWh]
1960 week 3	49.86	50.43	49.26
1989 week 31	11.63	10.27	10.23
2009 week 21	33.05	32.90	32.95
2009 week 50	45.38	45.15	45.47

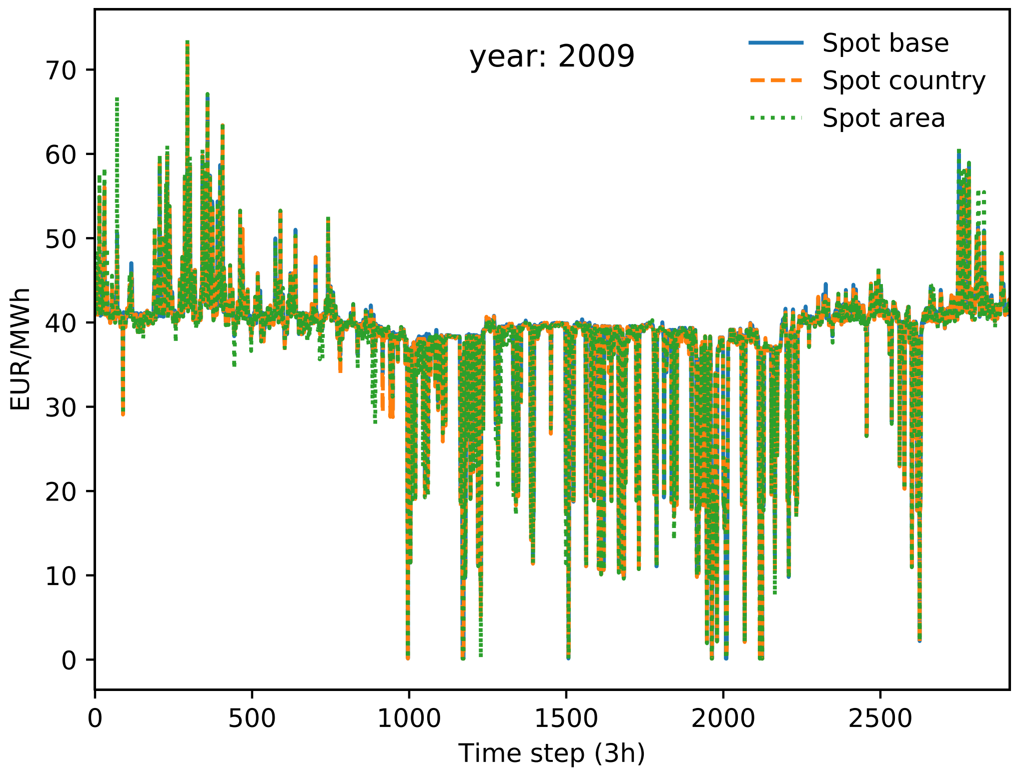

Figure 5. Simulated spot prices for weather year 2009. The simulations assume no reserve capacity requirements (base), reserve capacity requirements per country (country) and per price area (area).

Figure 6 shows the spot price for the three cases plotted for the four selected weeks. The spot price follows the same pattern and there are only small differences between the cases. It varies which case has the highest and lowest price between the weeks. For week 3 in 1960 the case with reserve prices per country has the highest average price, as seen in Table 6. From the plot we can see that this is a result of a slightly higher price for this case in a few time steps. The spot price in the case with reserves per area has slightly lower price in some time steps, and this case also has the lowest average price for this week. As 1960 is a dry year, it is reasonable that the spot price is higher when reserve capacity requirements are included. When reserve capacity is procured, less capacity is available in the spot market and this can lift the spot price. However, we also see that the case with reserve requirements per area has a lower average spot price than the base case in this week. This can be a local effect, as the results only consider the Ostland area (NO1) and the situation in this area can be different when reserve capacity is procured on a national level and on the smaller area level. An example of a similar situation for the same week is explained in more detail in section 5.1.1.

In week 31 of year 1989, the two cases with reserve requirements both have lower average prices than in the base case. Year 1989 is a wet year and there are low spot prices and a surplus of energy in week 31. The lower spot prices for the cases with reserve capacity can therefore be a result of capacity that continue to run (and produce) to provide downward reserves, even though the spot price is low, as previous discussed in section 1.3. In the base case, these units would not have the same incentives to continue running and would shut down if the spot price got too low.

For 2009 both week 21 and 50 have very similar spot prices in the three cases, and from Table 6 we see that there only are small differences in the average spot price.

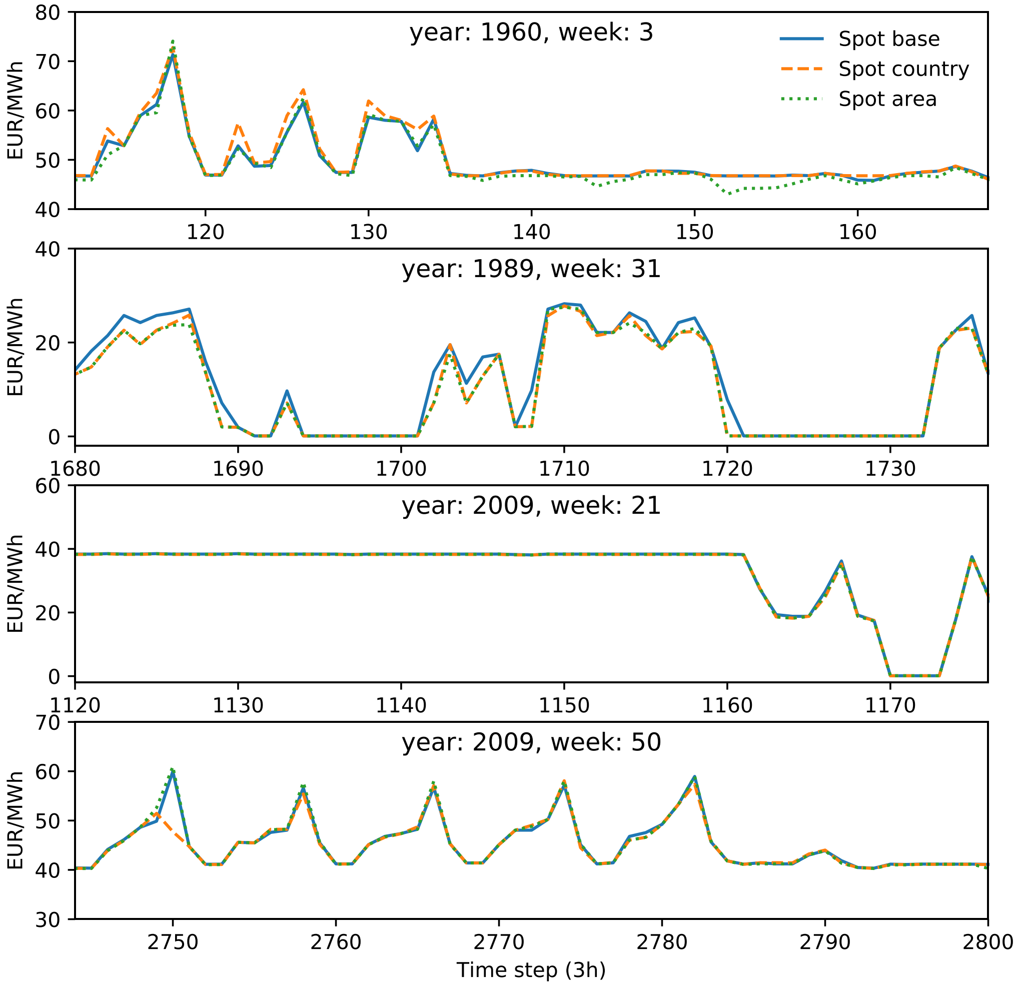

Figure 6. Simulated spot prices for week 3 in year 1960, week 31 in year 1989 and week 21 and 50 in year 2009. The prices are simulated using EMPS with upwards and downwards reserves and no reserve capacity requirements (base), reserve capacity requirements per country (country) and per price area (area) are assumed.

2.2 Dual of reserve capacity constraint

Up to this point we have only considered the impact on the spot price of procuring reserve capacity. The functionality in EMPS also provides the dual value of the reserve capacity constraints as an output. This value represents the cost of providing reserves, however, in the hydropower dominated areas the values do not comprise the complete cost picture. The results show some peculiar characteristics of resulting dual values in the hydro dominated areas. Firstly, if there is a positive dual value, the value in these areas is either close to zero or close to 3000. The rationing price for reserves (the penalty for not being able to meet the reserve requirements) is set to 2999 EUR/MW per hour, slightly lower that the rationing price of energy in the model (3000 EUR/MWh). It therefore seems that dual value only is positive when one of the reserve capacity constraints is broken. We also notice that the dual value for upwards and downwards reserves follow the same pattern, implying that the constraints are broken because the model cannot find a solution where both upwards and downwards reserves can be procured. These results do not fit well with the expected costs of providing reserve capacity and the prices for procuring reserve capacity seen in the markets today. The somewhat strange results are related to how the reserve capacity constraints are defined in the model and the use of heuristics to find the final solution. This is discussed further in Section 2.3.

Table 7 and Table 8 give the yearly and weekly average dual value of the upward and downward reserve capacity constraints. From Table 7 we see that yearly average dual values are considerably higher in the area case. We also notice that the average of the dual value of the downward reserve constraints is slightly higher than for the upwards reserve, meaning that the downward reserve constraints are broken more often than the upward reserve constraints. From Table 8 we notice that there not necessarily are positive dual values within the same week for the country and the area cases. A special case is week 3 in 1960 where we for the area case have an average dual value close to the rationing price, meaning that there is a high dual value of the reserve constraints in most time steps of this week.

Table 7. Yearly average dual values of the upward and downward reserve capacity constraints.

	Reserves country [EUR/MW]		**Reserves area [EUR/MW]**	
	Up	*Down*	*Up*	*Down*
1960	6.1791	6.1793	1006.186	1006.195
1989	0	0	712.678	712.682
2009	3.0895	3.0896	1071.064	1071.074

Table 8. Weekly average dual values of the upward and downward reserve capacity constraints.

	Reserves country [EUR/MW]		**Reserves area [EUR/MW]**	
	Up	*Down*	*Up*	*Down*
1960 week 3	53.552	53.554	2998.9996	2999.0
1989 week 31	0	0	0.32	0.39
2009 week 21	0	0	0	0
2009 week 50	160.656	160.661	0	0

2.2.1 Country case

Figure 7 and Figure 8 give the spot price and the dual of the reserve capacity constraints (upwards and downwards) for weather year 1960 when the reserves are defined on a country level. We see that there only are positive dual values for a few time steps, the rest of the time the dual value is zero which means that the constraint is not binding. From Figure 7 we see that the dual of the reserve constraints either is zero or reach the rationing price of reserves. The high dual values of the reserve constraints do not necessarily occur in the time steps with the highest spot prices, as seen in Figure 8. Figure 9 and Figure 10 plots the spot price and the dual of the reserve capacity constraints (upwards and downwards) for weather year 1989 and 2009 respectively. Figure 11 plots the same for four different weeks. We see that the spikes in the dual values of the reserves corresponds with peaks in the spot price, even if these are not the largest price peaks over the year. From the plots we do not see a clear link between the high dual values and the changes in the spot price.

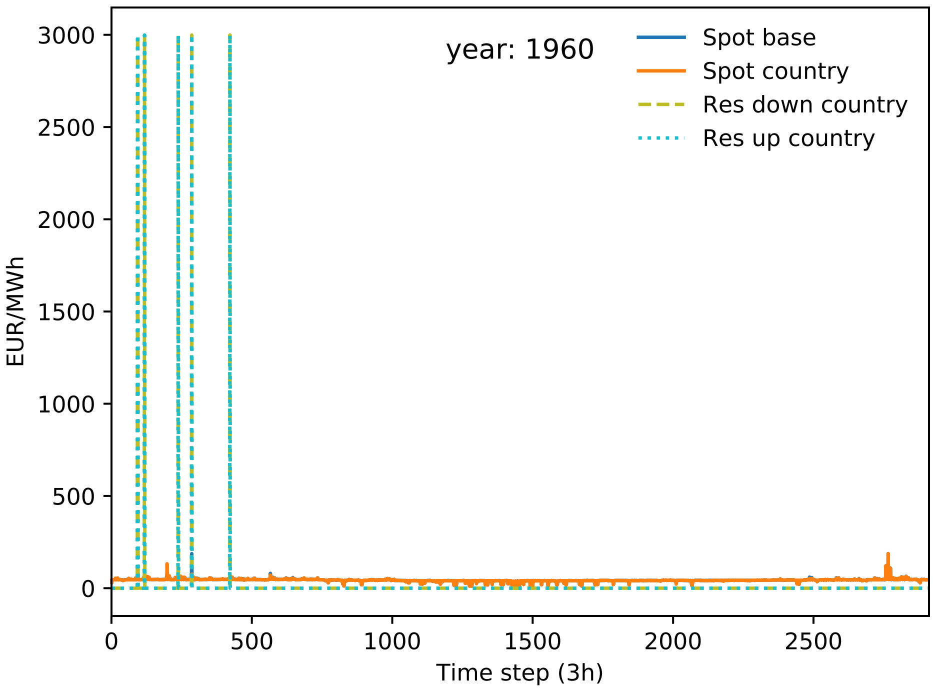

Figure 7. Plot of the simulated spot prices in the base and country cases together with the dual value of the upward and downward reserve capacity constraints in the country case. Plotted over one year, weather year 1960. The y-axis gives EUR/MWh for the spot price and EUR/MW per hour for the dual values of the reserve constraints.

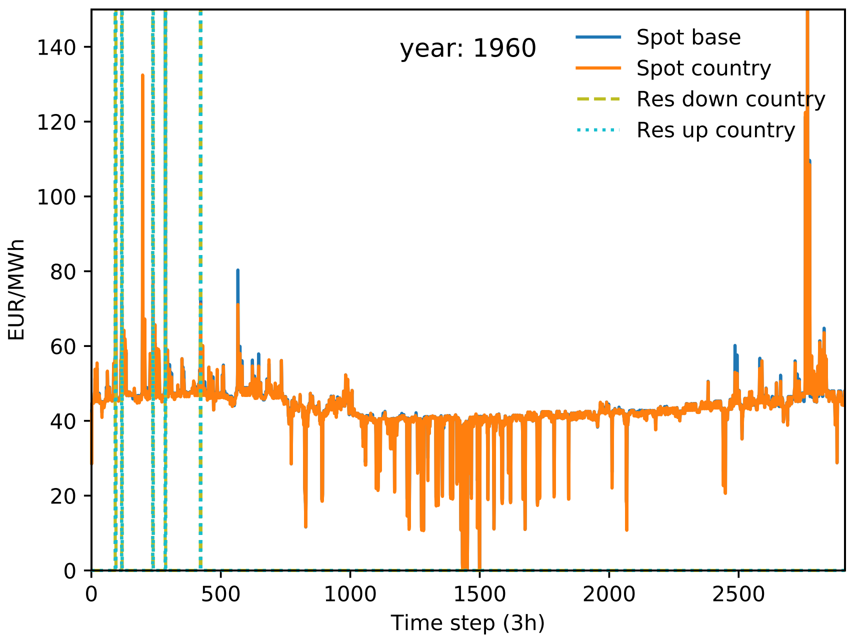

Figure 8. Plot of the simulated spot prices in the base and country cases together with the dual value of the upward and downward reserve capacity constraints in the country case. Plotted over one year, weather year 1960. With the y-axis capped at 150 EUR/MWh (EUR/MW per hour for the dual values of the reserve constraints).

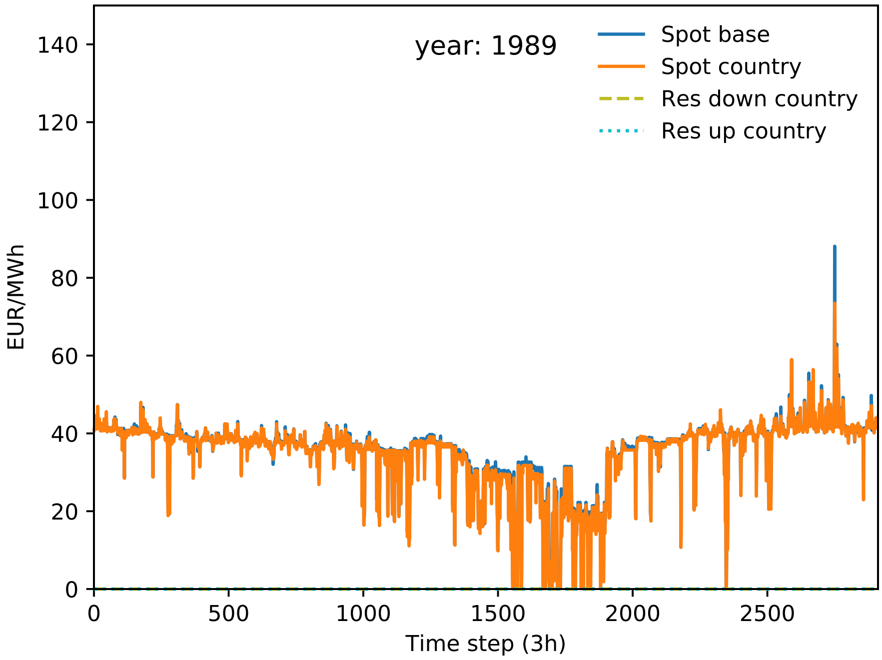

Figure 9. Plot of the simulated spot prices in the base and country cases together with the dual value of the upward and downward reserve capacity constraints in the country case. Plotted over one year, weather year 1989. With the y-axis capped at 150 EUR/MWh (EUR/MW per hour for the dual values of the reserve constraints).

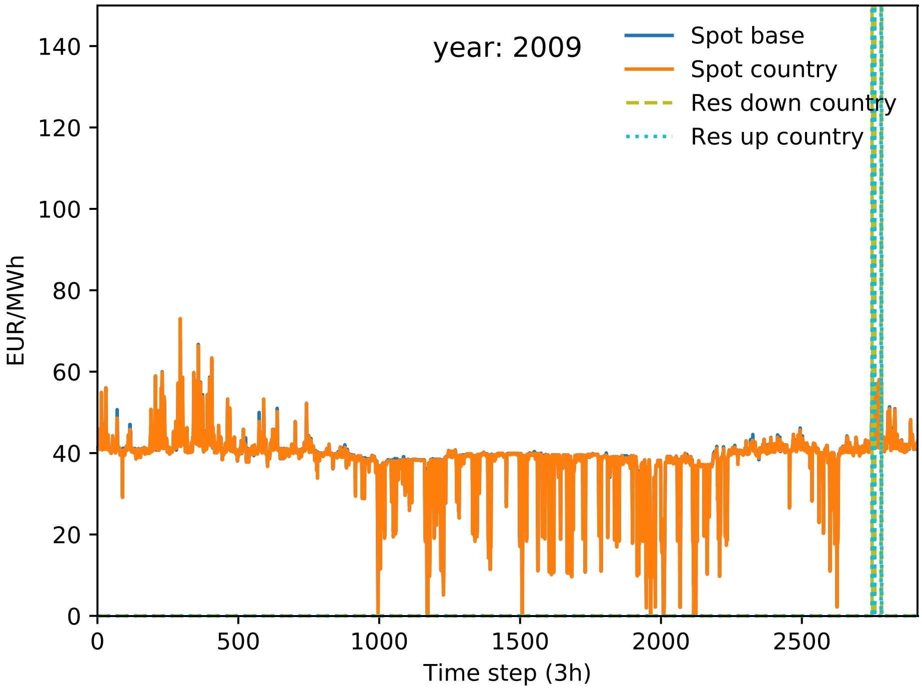

Figure 10. Plot of the simulated spot prices in the base and country cases together with the dual value of the upward and downward reserve capacity constraints in the country case. Plotted over one year, weather year 2009. With the y-axis capped at 150 EUR/MWh (EUR/MW per hour for the dual values of the reserve constraints).

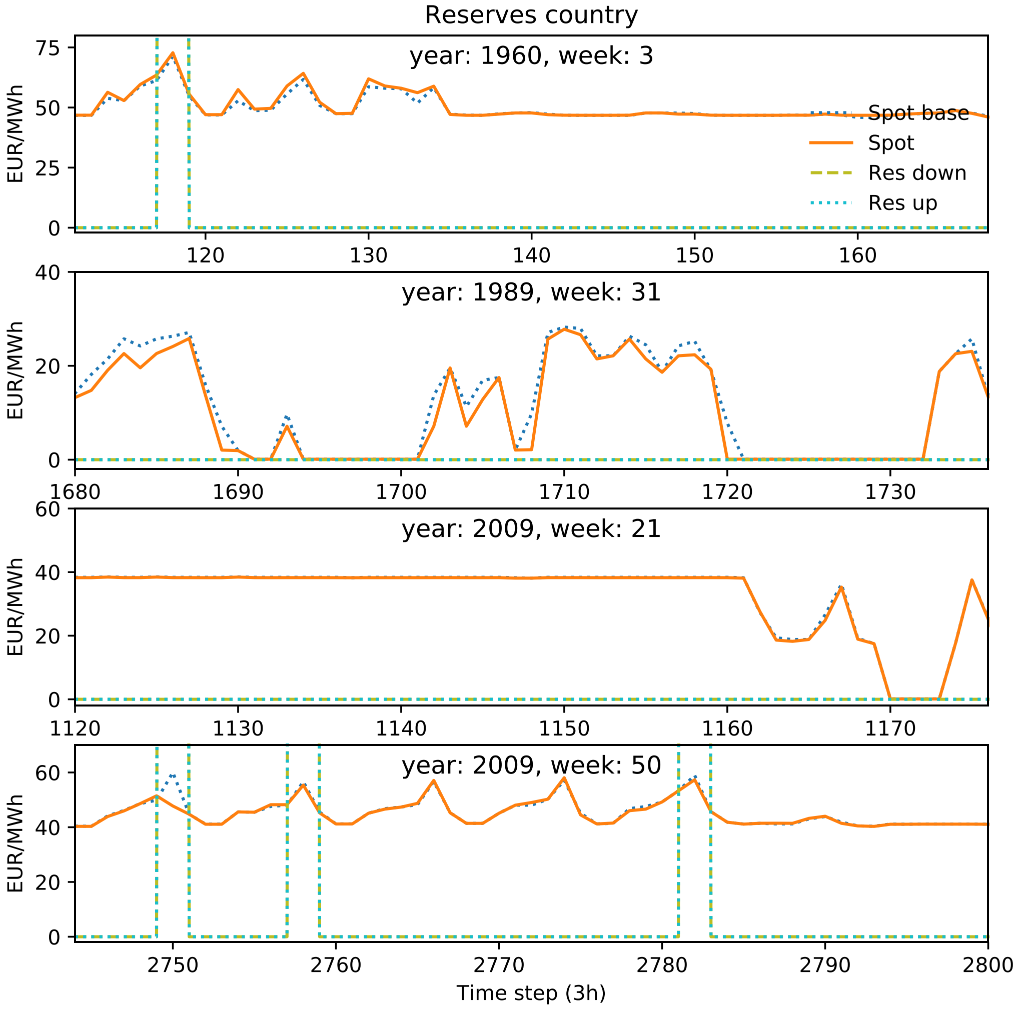

Figure 11. Plot of the simulated spot prices from the base and country cases together with the dual value of the upward and downward reserve capacity constraints in the country case. Plotted for four different weeks. The y-axis gives EUR/MWh for the spot price and EUR/MW per hour for the dual values of the reserve constraints and is capped to show the variation in the spot price.

2.2.2 Area case

For the area case, reserve requirements are defined per area, implying that each area have to cover its own need for reserve capacity and there is no exchange of reserve capacity between areas. This gives more hours with a high dual value of the reserve capacity constraints than in the country case. The simulated spot prices and the dual values of the reserve capacity constraints (upwards and downwards) for weather year 1960 are plotted in Figure 12 and Figure 13. We see that there are many more time steps with high dual values than when the reserve needs are handled on a national level. Figure 14 and Figure 15 shows the same for weather year 1989 and 2009. Figure 16 plots the spot prices and dual values of the reserve capacity constraints for four different weeks. There are only a few time steps with positive dual values in these specific weeks. An exception is for week 3 of year 1960 where the dual values of both the upwards and downwards reserve capacity constraints are high for the entire week. This means that it is not possible to provide the required levels of both upward and downward reserves in this week in Ostland (NO1). A rather surprising result is that the effect on the spot price is not larger when the dual value of the reserve constraint is high over such a long period. This is likely a consequence of how the reserve capacity constraint is implemented and is discussed further in section 2.3.

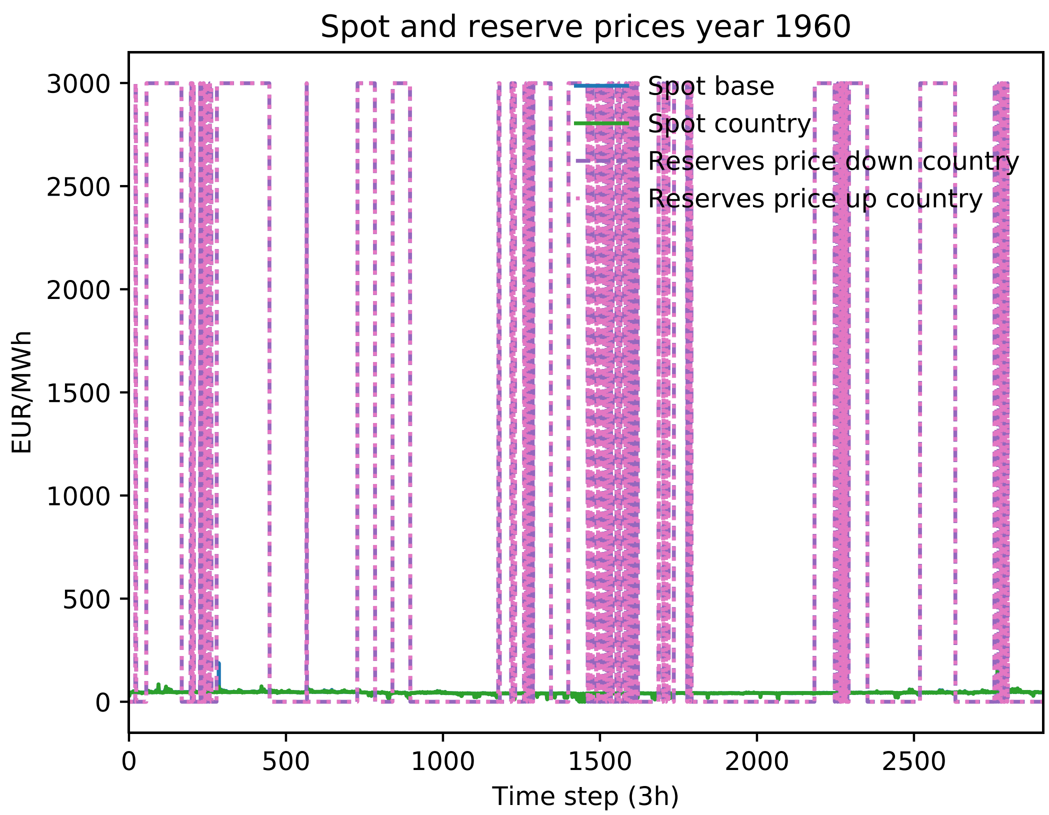

Figure 12. Plot of the simulated spot prices in the base and area cases together with the dual value of the upward and downward reserve capacity constraints in the area case. Plotted over one year, weather year 1960. The y-axis gives EUR/MWh for the spot price and EUR/MW per hour for the dual values of the reserve constraints.

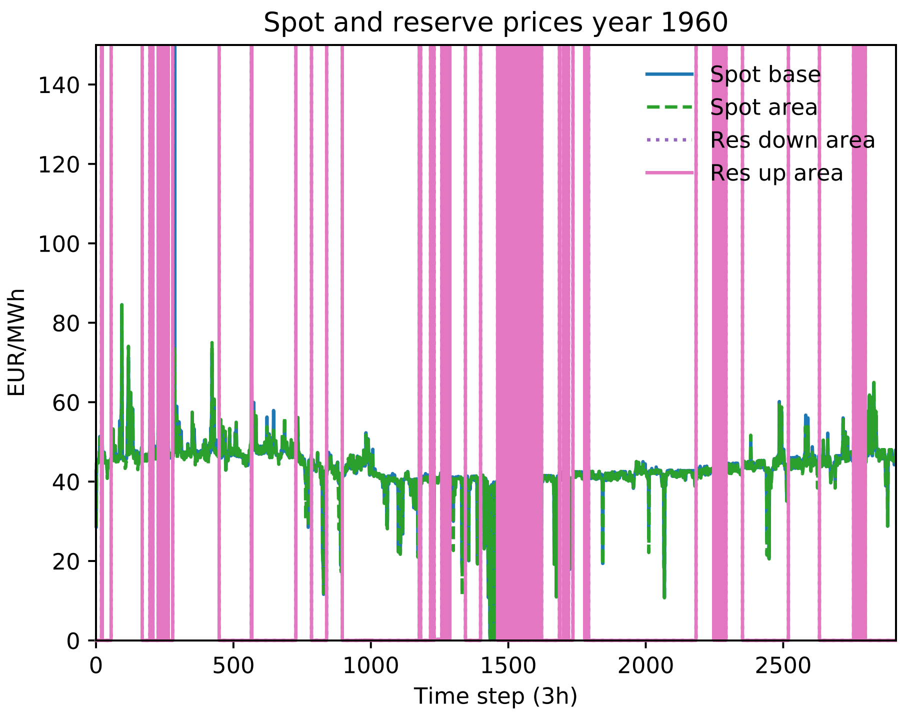

Figure 13. Plot of the simulated spot prices in the base and area cases together with the dual value of the upward and downward reserve capacity constraints in the area case. Plotted over one year, weather year 1960. With the y-axis capped at 150 EUR/MWh (EUR/MW per hour for the dual values of the reserve constraints).

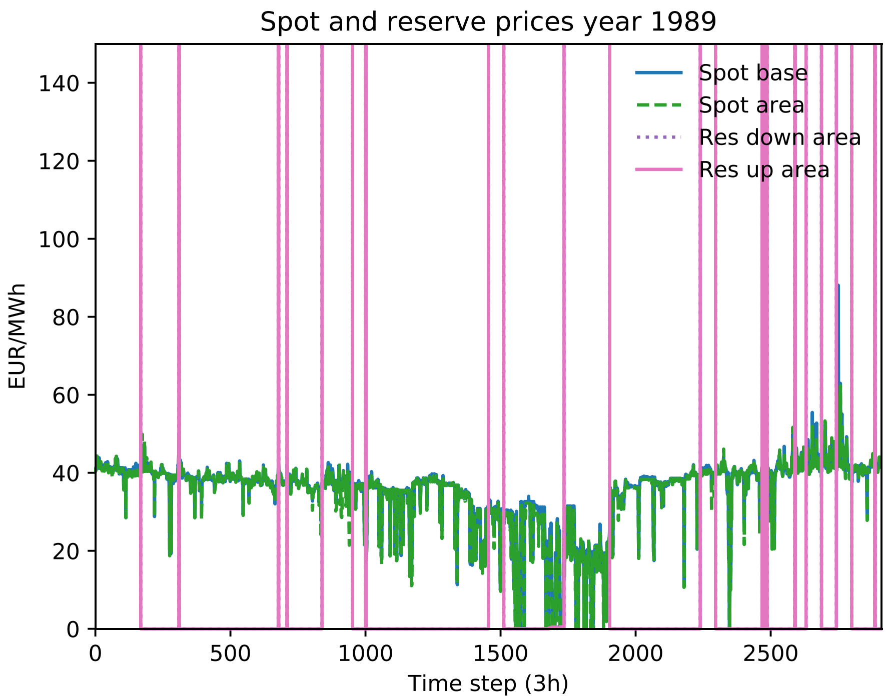

Figure 14. Plot of the simulated spot prices in the base and area cases together with the dual value of the upward and downward reserve capacity constraints in the area case. Plotted over one year, weather year 1989. With the y-axis capped at 150 EUR/MWh (EUR/MW per hour for the dual values of the reserve constraints).

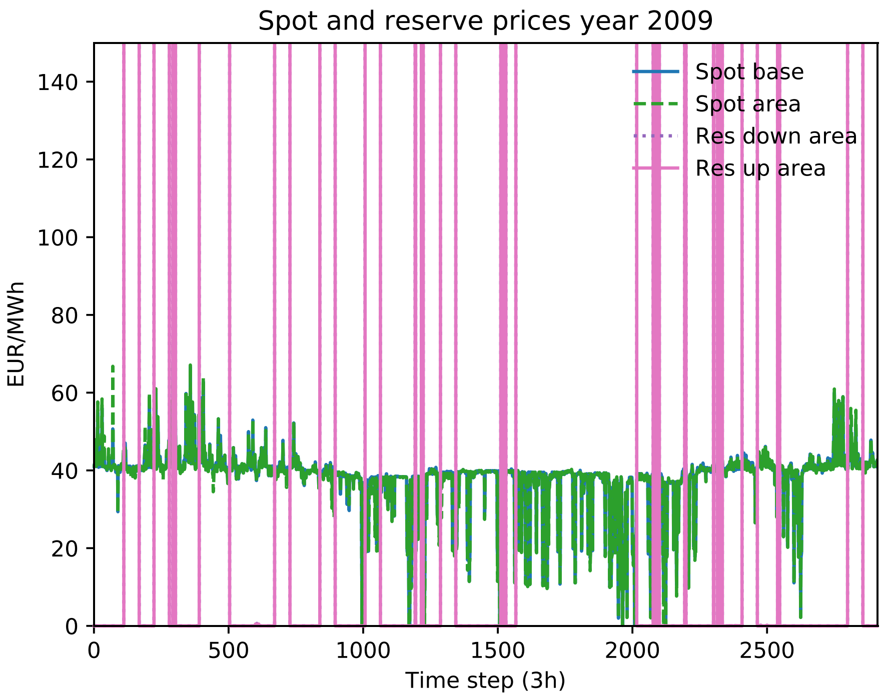

Figure 15. Plot of the simulated spot prices in the base and area cases together with the dual value of the upward and downward reserve capacity constraints in the area case. Plotted over one year, weather year 2009. With the y-axis capped at 150 EUR/MWh (EUR/MW per hour for the dual values of the reserve constraints).

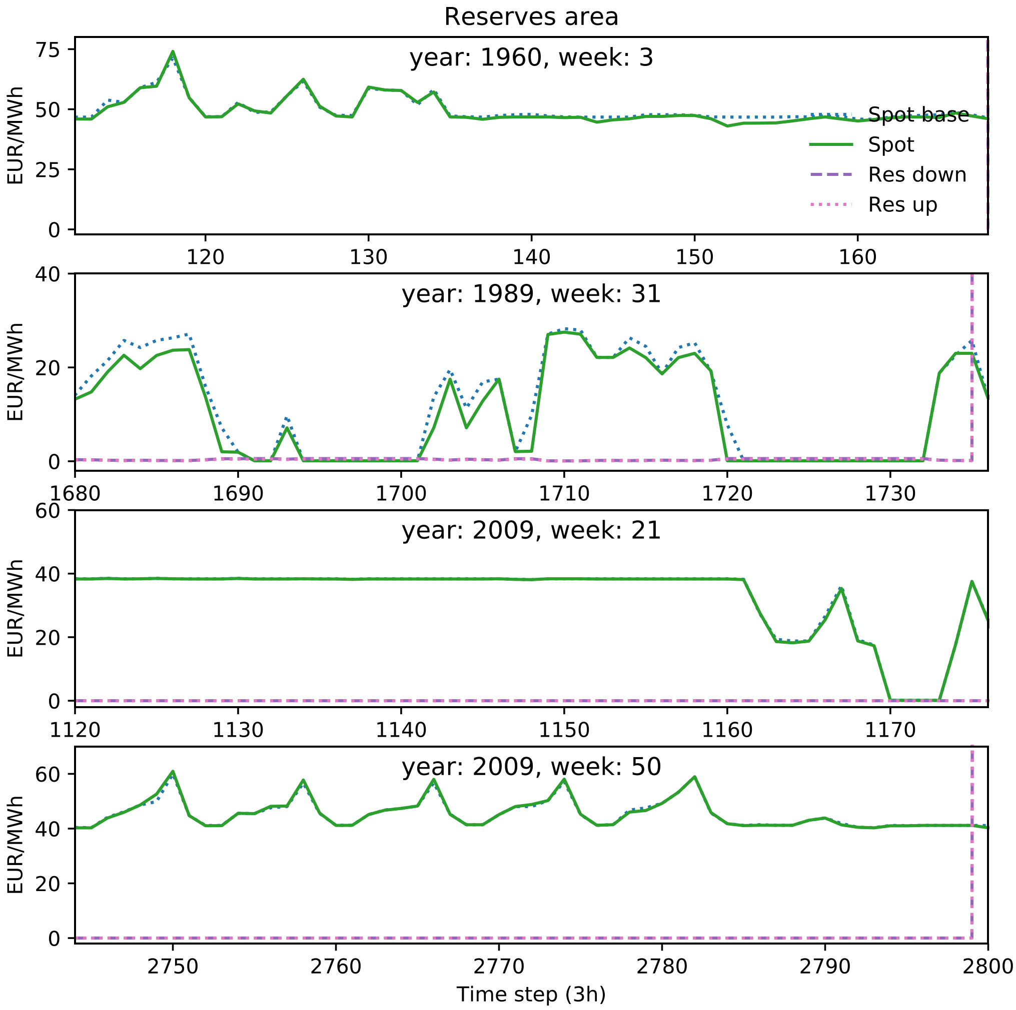

Figure 16. Plot of the simulated spot prices in the base and area cases together with the dual value of the upward and downward reserve capacity constraints in the area case. Plotted over for four different weeks. The y-axis gives EUR/MWh for the spot price and EUR/MW per hour for the dual values of the reserve constraints and is capped to show the variations in the spot price. For year 1960 week 3, the dual value for upwards and downwards reserves is high (close to 3000 EUR/MW) all week, and the graph is outside the plot for the whole period (can't be seen).

2.3 Challenges

2.3.1 Unstable functionality

Both versions of the implemented functionality for reserve capacity constraints in EMPS are unstable. Especially the version that includes both up- and downwards reserves, and several runs ended up with the model crashing. At first, all attempts with the drawdown procedure (tappefordeling) crashed when using this functionality for the low emission scenario. A second round of testing showed that the functionality became more stable when including all areas in the input file defining the reserve capacity. This significantly improves the performance of the functionality and we recommended to always do this when simulating with requirements for reserve capacity.

Areas without defined reserve capacity requirements can be defined as one large group with zero reserve capacity requirements, since they only are included in the input file to improve the stability of the model. The source of instability is not certain. It does not seem to be related to the feasibility of the reserve capacity requirements but is more likely a result of numerical issues.

2.3.2 Pricing reserve capacity

There are several challenges related to how the reserve capacity requirements are implemented in the EMPS model. The functionality gives the dual values of the reserve requirement constraints in the aggregated linear problem as output, which do not necessarily provide a good estimate of the price of procuring reserve capacity.

For instance, in practice it is possible to stop individual hydro plants/units and use the bypass gate to fulfil discharge constraints. In such cases the aggregate hydro model gives too little downward regulation capacity. Maximum hydro production is given by the sum installed capacity of all power plants in the area, limited by available energy in the aggregate reservoir. The aggregate hydro model representation therefore gives too much available capacity, especially for up regulation.

The algorithm in EMPS combines a linear problem and several heuristics. The constraints defining the reserve capacity requirements are implemented in the aggregated problem (linear) but is not included in the drawdown heuristic. This cause a challenge as no information is sent about the reserve capacity requirements into the drawdown procedure. Furthermore, no information nor dual values related to the reserve requirement from the drawdown procedure is sent back into the aggregated problem. There is therefore a loss of information about the costs of meeting the reserve requirements between the aggregated linear problem and the heuristic. The heuristics are especially important for the solution in hydropower dominated areas. Therefore, the dual values of the reserve constraints cannot be taken directly as the price of procuring reserve capacity in these areas. Still, the values can give signals on how tight the market is and if there is sufficient flexibility available in the system to provide reserve capacity.

Why do we not see dual values between zero and the rationing penalty?
In the simulations, when considering hydropower dominated areas, the reported dual values of the reserve capacity constraints are close to zero or close to the penalty value for breaking the constraint. This can be seen for Ostland both when defining reserves on a national level and on an area level. In a hydropower-based system there is often a lot of available flexibility and it is therefore reasonable that reserve capacity often can be offered for free or at a very low cost. However, the simulations imply that the costs of changing your hydropower schedule, for example the cost of breaking a bypass restriction to meet the reserve requirement, not necessarily are reflected in the reported reserve capacity dual values. This could be a consequence of that the dual values of the reserve constraints in the aggregated problem only reflect the increase in cost in the aggregated problem, and not necessarily costs that occur within the drawdown procedure. For this reason, the actual cost of providing reserves from the hydropower system can be between zero and the penalty value without this being represented in the dual values given as output. For areas where thermal power plants are used to deliver reserve capacity, and the drawdown procedure is not used (since there is no hydropower), the reported dual values of the reserve capacity constraints better comprise the costs of providing the reserve capacity and we see values between zero and the penalty cost.

Why are there so many time steps with high dual values in the area case?
In the area case we see some peculiar behaviour of the dual values. Firstly, there is a significant increase in the amount of time steps where the dual value of the reserve capacity constraints is at the penalty cost. This imply that the reserve capacity requirements cannot be met in these time steps. Secondly, we do not see a large effect on the spot price, even if the dual of the reserve capacity constraint is high over a longer period (e.g. week 3 in 1960). Normally, it

should be possible to provide the required levels of reserves in areas with lots of hydropower. On the other hand, Ostland does not have the largest hydropower resources in Norway and a large share is unregulated, so in some periods a shortage of regulated hydropower can occur. However, a second explanation can lay within how the maximum and minimum production levels are set. In the EMPS model, the levels are taken from the drawdown heuristic where several assumptions on the operation of the system is incorporated into the minimum discharge level. This level can therefore become quite high in some situations, especially in Ostland with long river systems with little storage capacity. In these cases, the minimum production level does not necessarily represent a level that is required to deliver reserve capacity, but a minimum discharge level required to achieve the best representation of detailed system in the aggregate model, not considering reserve capacity allocation. As a consequence, the model does not see a feasible solution to deliver the required reserve capacity, as it does not see the option of rescheduling in the drawdown procedure to get different maximum and minimum levels. The theory of the high dual values of the reserve constraint being a result of the challenges in the modelling, i.e. how the maximum and minimum levels are set, and not the market is supported by the lack of change seen in the spot price in the same periods.

3 EMPS (V10)

The dataset was converted to EMPS version 10 (V10). This version is compatible with EMPS-W and PriMod and this was a necessary step before running simulations with these models. The EMPS version 10 model was only run with functionality for requirements for upwards reserve capacity per country. The dual values of the reserve requirement constraints are not available from the results. The spot prices are presented in section 3.1, and some comments are given in 3.2.

3.1 Spot price with upwards reserve capacity requirements

This section presents spot price results from the simulation with EMPS V10 for the three selected years and the four focus weeks. Figure 17 shows the simulated spot prices for the three different weather years. The results give some very high price spikes in Ostland for the year 1960 and 1989. Simulations with EMPS V9 or EMPSW does not give such high price spikes. This is because of differences in how the models are run (EMPS V10), see 3.2, and differences in the modelling (EMPSW uses formal optimization).

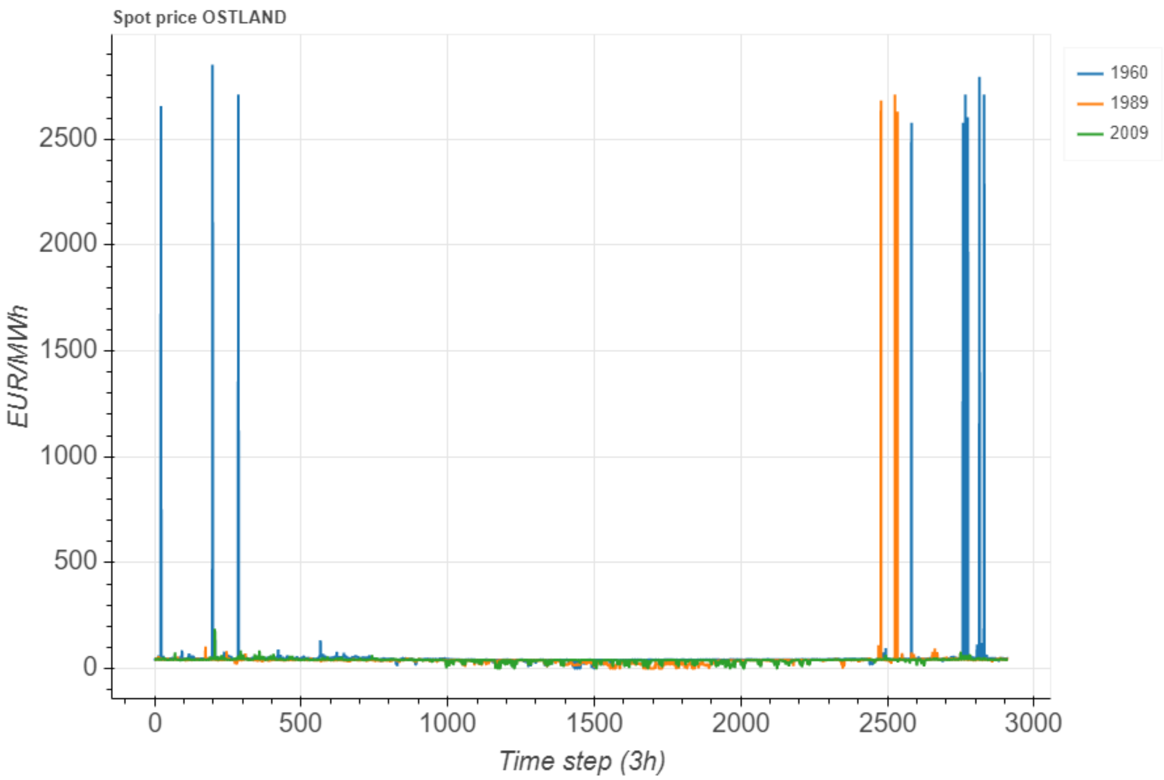

Figure 17 Plot of the simulated spot price for three weather years using the EMPS version 10 model with upward reserve requirements per country.

Zooming in, Figure 18 reveals the differences in spot price for the three years in greater detail. The overall pattern is quite similar to the results from the EMPS V9 simulations presented in Figure 2 (without reserve requirements).

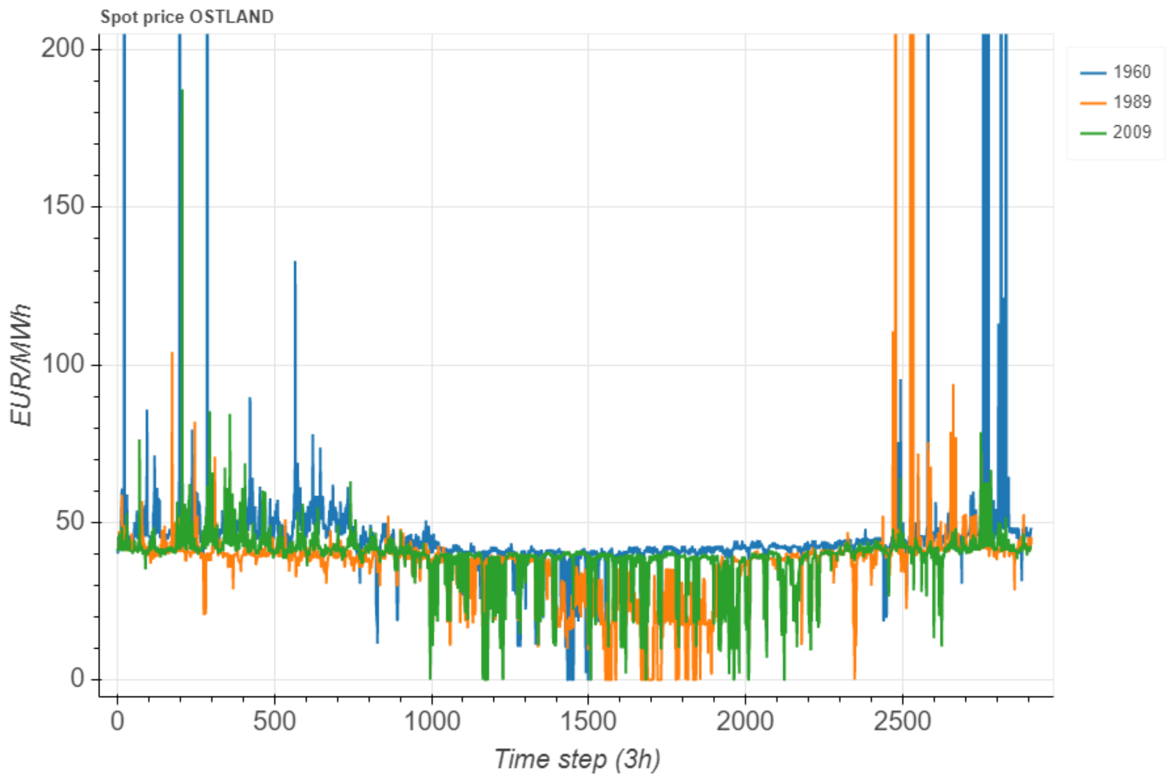

Figure 18 Plot of the simulated spot price for three weather years using the EMPS version 10 model with upward reserve requirements per country. The y-axis is capped at 200 EUR/MWh.

The average spot prices for the three years are presents in Table 9. The dry year 1960 has the highest average spot price. Although the wet year 1989 has the lowest prices during summer, the high spot prices towards the end of the year brings the average price for the year close to the average for year 2009.

Table 9 Average spot price in Ostland in three selected simulation years and all years.

	Spot country [EUR/MWh]
1960	51.91
1989	38.75
2009	38.90
All years	41.71

The average spot prices in the four selected focus weeks is presented in Table 10.

Table 10 Average spot price in Ostland in four selected weeks.

	Spot country [EUR/MWh]
1960 week 3	48.78
1989 week 31	8.03
2009 week 21	32.43
2009 week 50	48.01

3.2 Comments to the simulations

A comparison of the spot price results from EMPS V9 and EMPS V10 would be in place.
We did a comparison of the spot price results from EMPS V9 and EMPS V10 for the selected weeks, but the differences we found were larger than expected and without any clear pattern. Both EMPS V9 and EMPS V10 were run with the same model calibration, which was automatically transferred when updating the dataset. However, it was discovered that EMPS V10 (and EMPSW) was run without temperature adjustment of demand while EMPS V9 was run with temperature correction (demand and thermal efficiencies?). Comparing the differences in spot prices with the differences in demand, we saw that this explained the deviations. This makes a direct comparison between the results from EMPS V10 and EMPS V9 inappropriate. Running with temperature correction can give large differences in the load profiles as the profiles are adjusted depending on the historical temperature profiles. This can result in a different strategy calculation (water value calculation) than without temperature correction, and have large implications for the results. The missing temperature correction setting was discovered after several of the other runs with the version 10 dataset was finished and there was not time and resources left for a complete rerun.

Both EMPS V10 and EMPS V9 is run as series simulation with the same initial reservoir filling for the first year. Throughout the simulation, the reservoirs can develop differently, and one can expect larger spot price differences for the inflow year 2009 than year 1960 because the differences will accumulate. The effect of different distribution of water between the reservoirs can also give unequal prices.

4 EMPSW

The EMPSW model was run three times for each case (base, national reserve markets and area based reserve markets) as a parallel simulation of all 58 weather years with initial reservoir fillings corresponding to the years 1960, 1989 and 2009. These initial reservoirs were obtained from the results from a series simulation by EMPS V9, run with national reserve requirements. The model does not return the dual value of the reserve requirements, so only the spot price results are shown and discussed in section 4.1. The EMPSW was also run as a necessary step to provide a strategy for hydro resources represented by individual water values for all hydro reservoirs to the PriMod model.

4.1 Spot prices

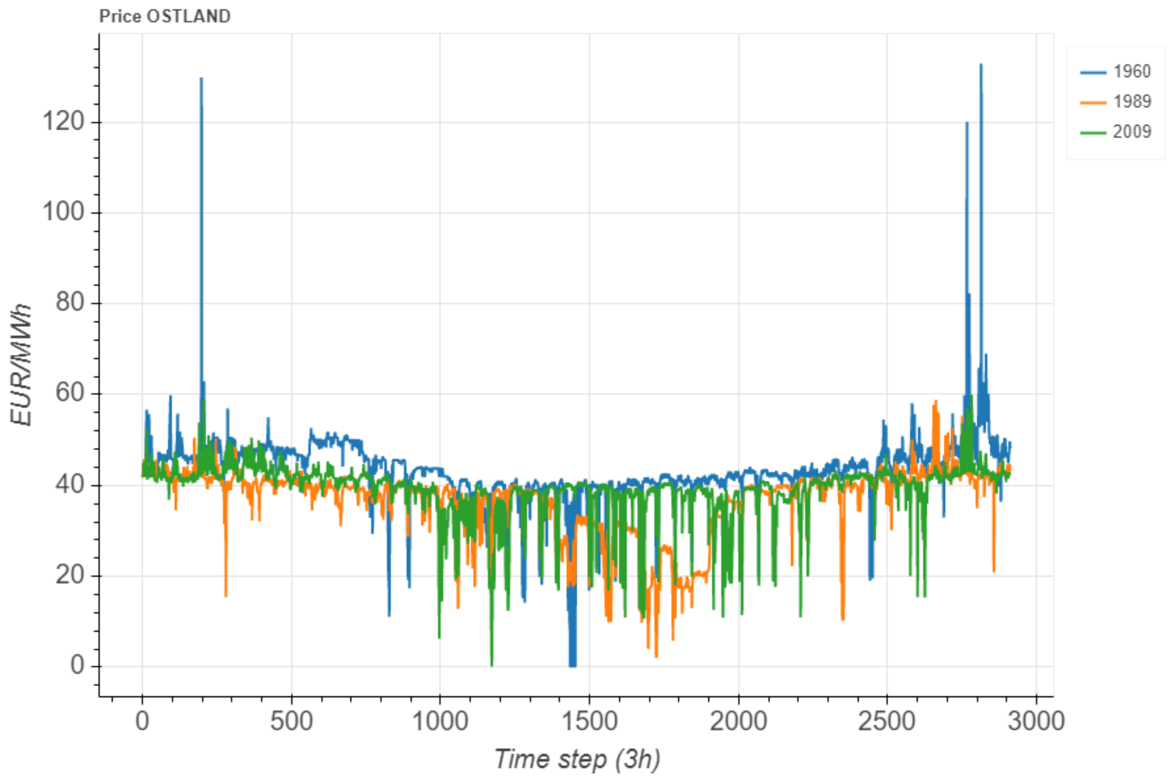

Figure 19 The spot price for the three selected years simulated with EMPSW and reserve requirements per country.

Figure 19 shows the simulated spot price from EMPSW for the three different weather years with requirements for reserve capacity per country. As expected, the dry year 1960 has a generally higher price level due to higher water values, giving fewer price dips and some high spikes. The wet year 1989 has lower water values resulting in lower price level and some weeks with very low prices during summer. 2009 also has a lower price level with many price dips, but the price level is more robust during summer compared to 1989. The prices are similar to the results from EMPS V9 and V10. The differences are mainly due to the fact that EPSW uses formal optimization in the disaggregation while EMPS is based on heuristics.

4.1.1 Impact of reserve capacity requirements

This section aims at comparing the spot price for the different cases. Table 11 presents the average spot price in Ostland for the selected simulated years for the three reserve cases. The differences between the cases for each year are very small, smaller than the averages from EMPS V9, and there is no evident pattern, as with the yearly averages from the EMPS V9 model. But the base case for year 1989 and 2009 also here provides the highest average spot price.

For year 1960, the area case yields the highest average spot price by a small margin. The cases with and without reserve requirements gives almost the identical average spot prices.

Table 11 Average spot prices (EUR/MWh) in Ostland in three selected simulation years for the spot, country and area case simulated with EMPSW.

	Spot base [EUR/MWh]	**Spot country** [EUR/MWh]	**Spot area** [EUR/MWh]
1960	43.42	43.40	43.43
1989	36.69	36.66	36.65
2009	39.16	39.14	39.15

Figure 22, Figure 21 and Figure 22 shows a plot of the spot price for the three different cases for the years 1960, 1989 and 2009. These plots also show that the prices are very similar between the cases. For 1989 we can see that the spot price in the base case is highest in some time steps during summer.

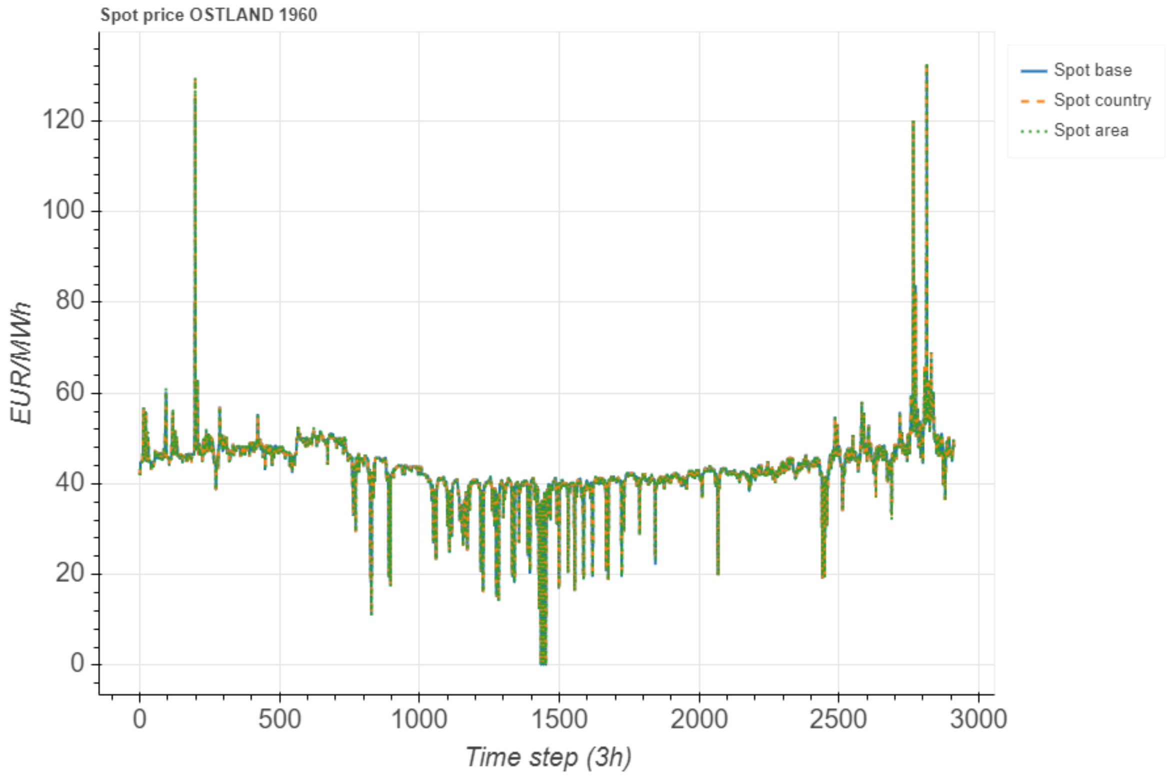

Figure 20 Simulated spot prices for weather year 1960 (Dry?). The simulations are done with no reserve capacity requirements (base), reserve capacity requirements per country (country) and per price area (area).

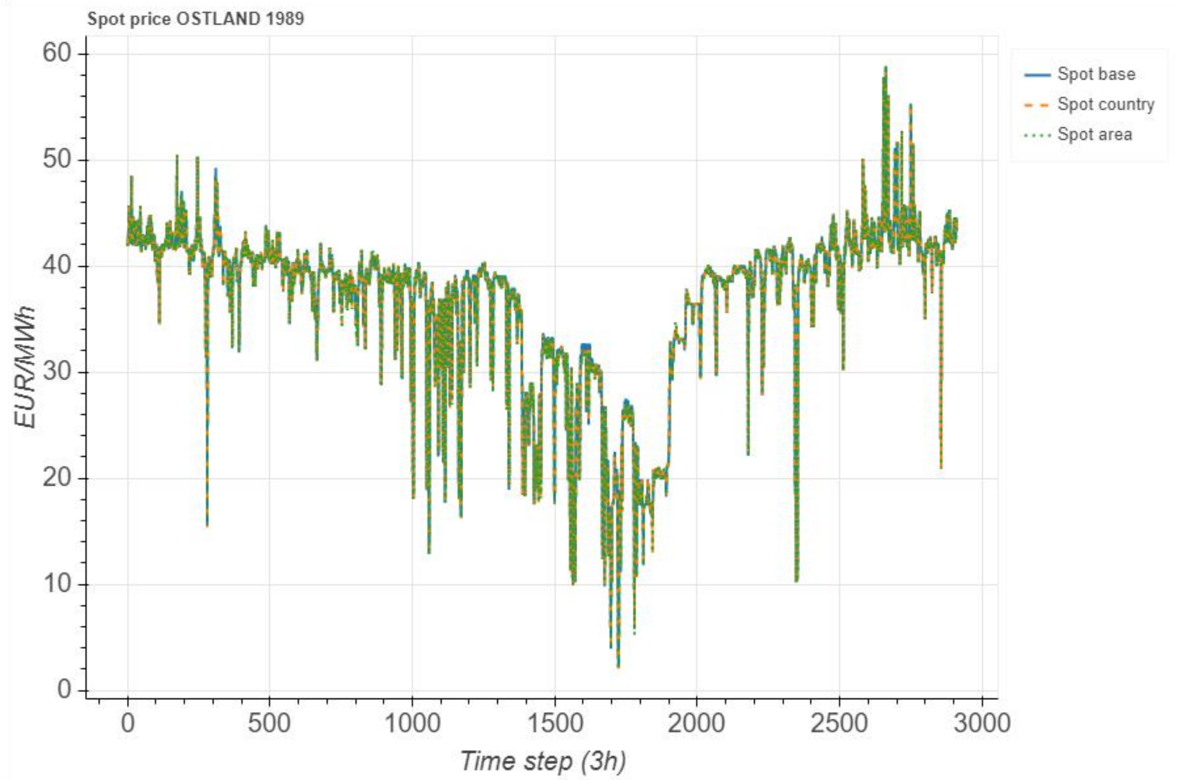

Figure 21 Simulated spot prices for weather year 1989 (Wet). The simulations are done with no reserve capacity requirements (base), reserve capacity requirements per country (country) and per price area (area).

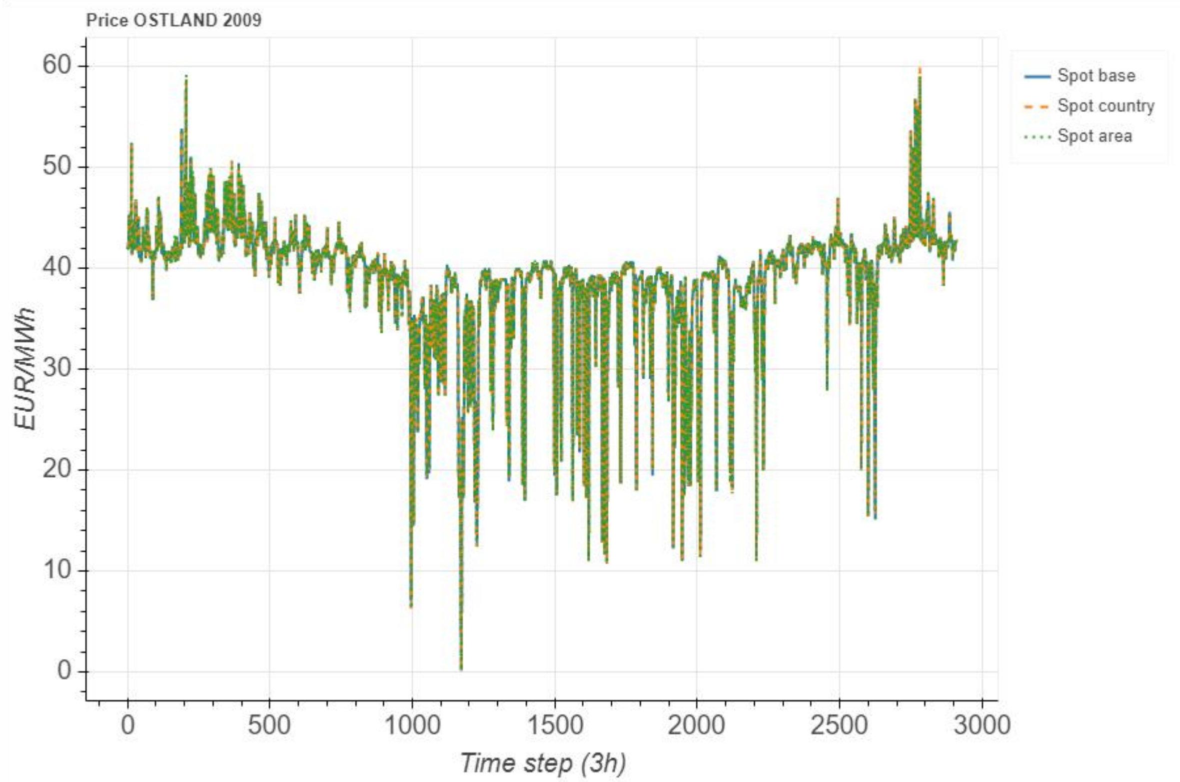

Figure 22 Simulated spot prices for weather year 2009 (Normal). The simulations are done with no reserve capacity requirements (base), reserve capacity requirements per country (country) and per price area (area).

Table 12 shows the average spot price for the selected weeks from EMPSW. We see that the winter weeks (3 and 50) have the highest spot prices, and that the average spot price is lowest in the summer week 31. The average spot price between the cases for each year and week is quite similar, and do not show any clear pattern with regards to which case that has the highest and lowest average spot price. This will depend on the effects of the reserve requirements, and the situation in the power system.

Table 12 Average spot prices (EUR/MWh) over the selected weeks from the EMPSW simulations.

	Spot base [EUR/MWh]	**Spot country** [EUR/MWh]	**Spot area** [EUR/MWh]
1960 week 3	47.18	47.25	47.28
1989 week 31	16.52	16.30	16.27
2009 week 21	32.78	32.71	32.71
2009 week 50	46.34	46.35	46.43

Figure 23 shows the spot price for the three cases for the four selected weeks. The spot price follows the same pattern and there are very small differences between the cases. It varies which case has the highest and lowest price between the weeks. For 1960 week 3 the case with reserve prices per area has the highest average price and from the plot we can see that this is a result of a slightly higher peak prices for this case. The spot price in the case with no reserves has slightly lower price in many time steps, and this case also has the lowest average price for this week. This is explained in more detail in section 2.1.3.

In year 1989 week 31, the situation is opposite to week 3. Here, the case with no reserve requirements have the highest average spot price, whereas the area case has the lowest average price. Year 1989 is a wet year and there are low spot prices and a surplus of energy in week 31. The lower spot prices for the cases with reserve capacity can therefore be a result of hydropower plants forced to produce to provide enough downward capacity, even though the spot price is lower than their marginal cost.

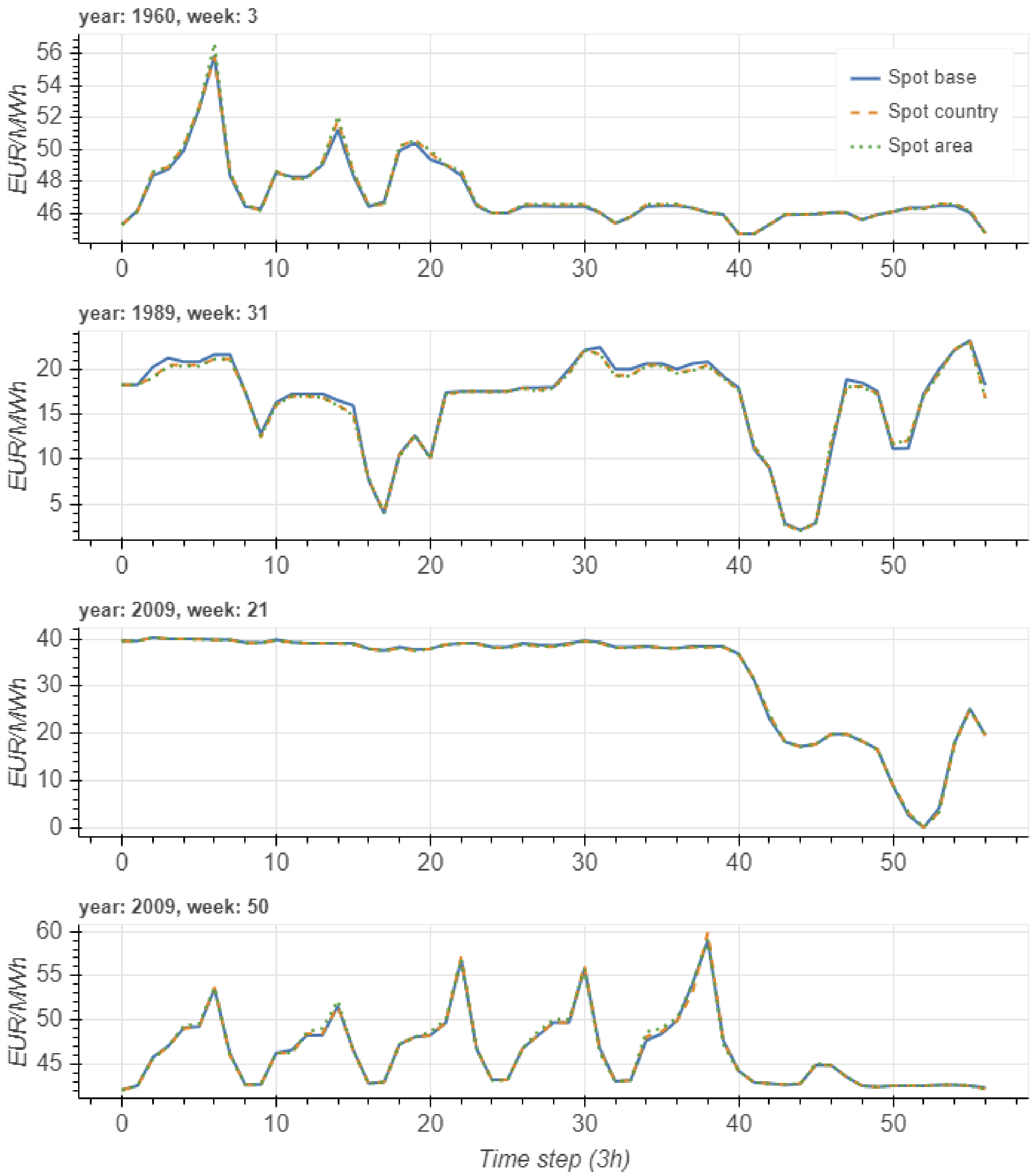

Figure 23 Simulated spot prices for week 3 in year 1960, week 31 in year 1989 and week 21 and 50 in year 2009. The prices are simulated using EMPSW with no reserve capacity requirements (base), reserve capacity requirements per country (country) and per price area (area).

For all practical purposes the results are identical and from these calculations with EMPSW it can be concluded that reserve procurement has no impact on the spot prices.

4.2 Challenges

The EMPSW model does not provide the dual value of the reserve capacity constraints. This makes it hard to verify how much these requirements are binding for the optimization problem, and what the prices for reserving capacity will be. For this report, it would be interesting to compare the reserve capacity prices between all models used, but we cannot.

5 PriMod

The PriMod model has been run for all four chosen weeks for the four described cases (see section 1.2.1). The initial reservoir fillings and individual water values used in the PriMod simulations come from the EMPSW results for the country case for the corresponding year and week. In the simulations with weather data from 1960 and 1989, results from simulations with the country case from EMPSW was used as input for simulating both the country and area cases in PriMod. For the simulations with weather data from 2009, simulations of the base, country and area cases in EMPSW were used for input data to the corresponding cases in PriMod. This has been illustrated in Figure 1.

5.1 Spot prices and reserve prices

Table 13 Average spot price in Ostland from the PriMod results.

	Spot base [EUR/MWh]	**Spot country** [EUR/MWh]	**Spot area** [EUR/MWh]	**Spot area ex** [EUR/MWh]
1960 week 3	46.18	46.19	46.19	46.20
1989 week 31	15.25	15.46	14.39	15.66
2009 week 21	32.00	31.93	31.84	32.00
2009 week 50	46.56	46.58	46.70	46.54

Table 13 summarizes the average spot price in Ostland from all the PriMod simulations. The average spot price is quite similar between the cases within each week. The difference between the cases is largest in week 31 with weather data from 1989 (the high inflow year). There is no clear pattern of which cases result in the highest or lowest average spot prices. This depends on the system situation for each week, the price level and profile in addition to the effect of the reserve requirement. This section presents the spot price results and the dual value of the reserve requirements (hereafter called the reserve price) for each week.

5.1.1 Week 3 1960

Week 3 with weather data from 1960 starts with high spot prices and price spikes the first three days, then the price level drops to around 45 EUR/MWh for the last four days of the week (see Figure 24). This is mainly because the wind and solar power production in the system increases from Wednesday night. The spot prices between the four cases in PriMod is very similar. The differences are most evident on the highest and lowest prices, but the difference is only about 1 EUR/MWh at most. The spot price spread is generally biggest in the most restricted case with reserve requirements per price area and no exchange of reserves, the area case (see Figure 24). This can be explained by looking at the dual values of the reserve capacity requirements. There is a cost of reserving upwards capacity in the area case in Ostland when the prices are high. In these hours, plants must hold back production to deliver reserve capacity up, and production must come from power plants with higher marginal cost or be imported at a higher price. When prices are low (especially at the beginning of Saturday), the production from hydropower in Ostland is higher and imports are lower in the area case, because hydropower plants are forced to produce to deliver enough reserve capacity down. This results in lower production in the neighbouring areas exporting power to Ostland. As more expensive production supplying reserves will displace cheaper production, the spot price will be lower because the marginal cost of delivering one more unit of power will come from less expensive production through import in the area case in the periods with a price for delivering downward reserve capacity.

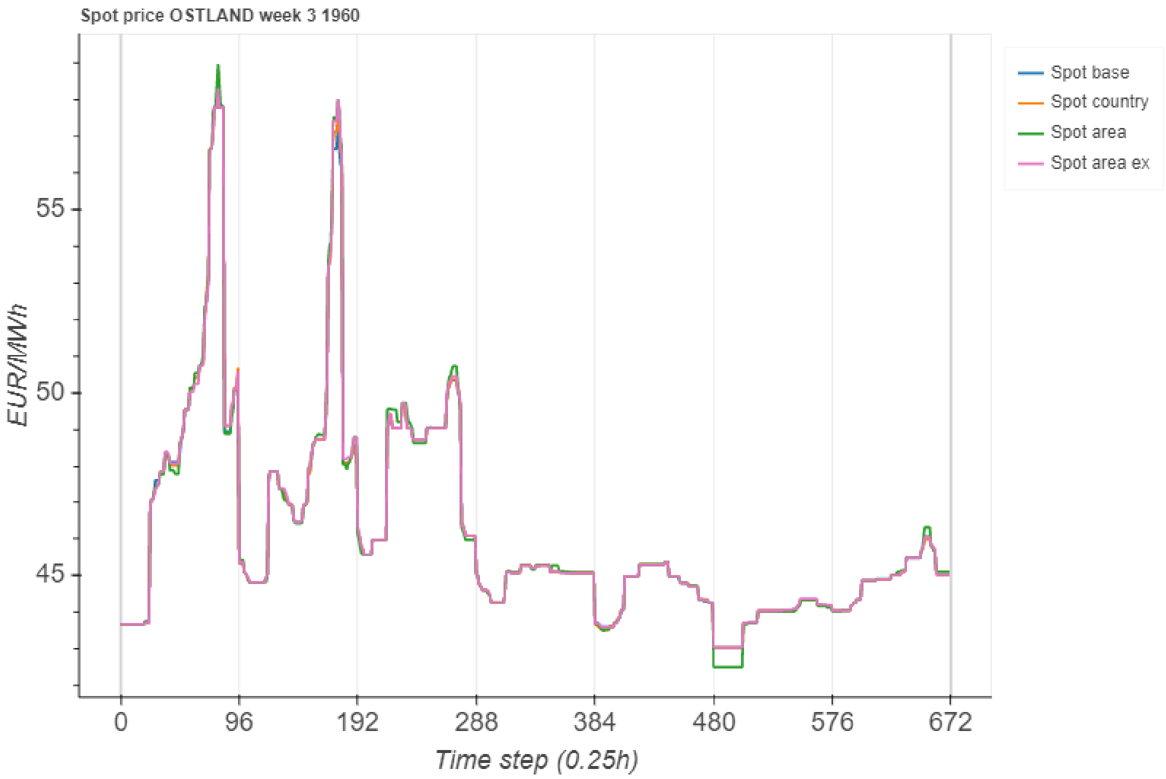

Figure 24 Simulated spot prices for week 3, weather year 1960. The prices are simulated using PriMod with no reserve capacity requirements (base), reserve capacity requirements per country (country), per price area (area) and per price area with exchange (area ex).

The dual value of the constraint for upward reserve capacity is presented in Figure 25. There is a small price around 1 EUR/MW for reserving capacity for up regulation in Norway in the least limited reserve case (country) in the periods corresponding with the two highest spot price peaks. In these two periods about 70-80 MW upward reserve capacity is reserved in Ostland. This capacity is cheap or free to reserve due to the effect that hydropower plants have their best efficiency point below maximum. So, producing at best efficiency will provide some free upward reserve capacity. But this "free capacity" is only half of the reserve requirement for Ostland in the area case. The dual of the reserve capacity constraint for upward reserves is therefore much higher (up to 12 EUR/MW). The reason is that Ostland then needs to provide additional capacity from within the area leading to a less optimal solution, and hence a cost for delivering the capacity. When allowing for exchange of reserves with other areas, the situation in Ostland is less strained, and the reserve capacity price for upwards regulations is more like the case with a national reserve market. The price however, is slightly higher than in the country case because in the area exchange case capacity must be allocated on the grid to be able to share reserves. This leads to a slightly more costly solution than in the country case. Ostland is a net import area. In the area exchange case, Ostland sometimes cannot import as much as wanted in the spot market if upward reserve capacity must be imported. From Figure 25 we see that Ostland imports upward reserve capacity without costs in most periods because the upward reserve capacity price we see in the area case disappears when exchange of reserves is allowed.

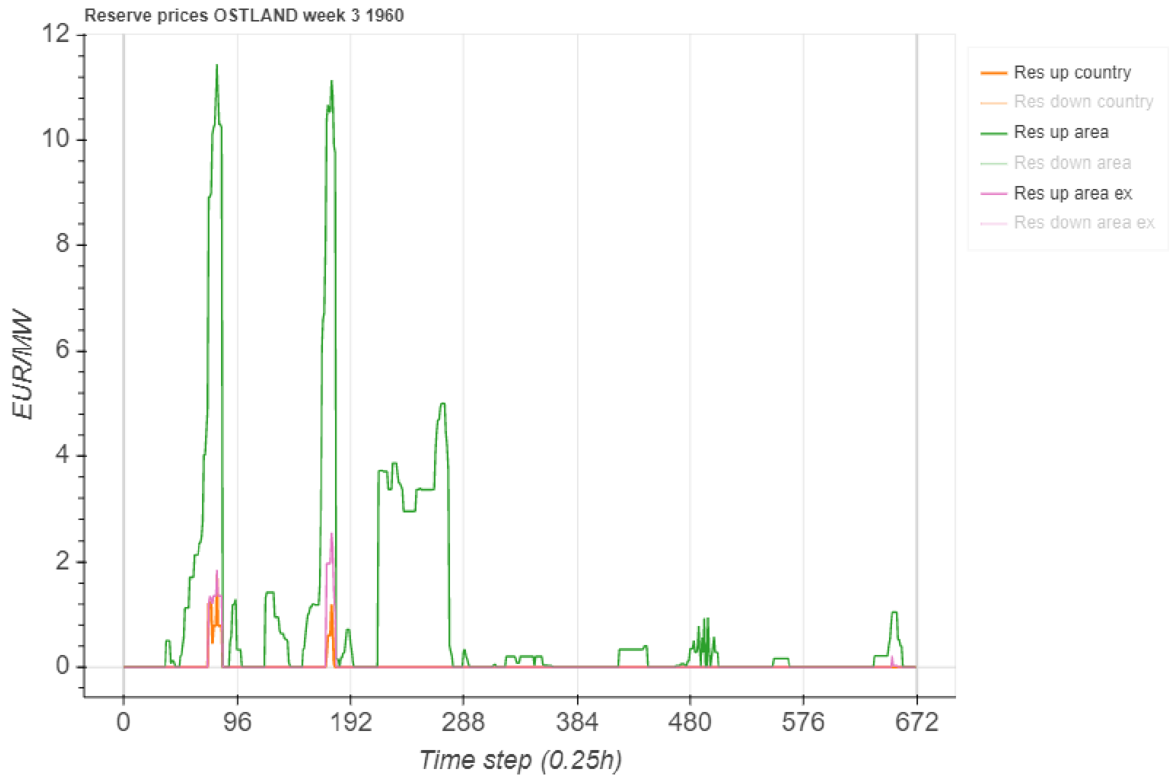

Figure 25 Plot of the dual value of the upward reserve capacity constraints in the country, area and area exchange case for week 3, weather year 1960.

As seen in Figure 26, there is no dual value for reserving downward capacity in the country or area exchange case. In the most restricted case with reserve requirements per area, and no possibility for exchange, there is a small cost of reserving downwards capacity at the beginning of Friday and Saturday when the spot price is lowest. In these periods, Ostland must produce more on plants that normally would not run or to be able to cover the requirement for down capacity, leading to a more costly system operation.

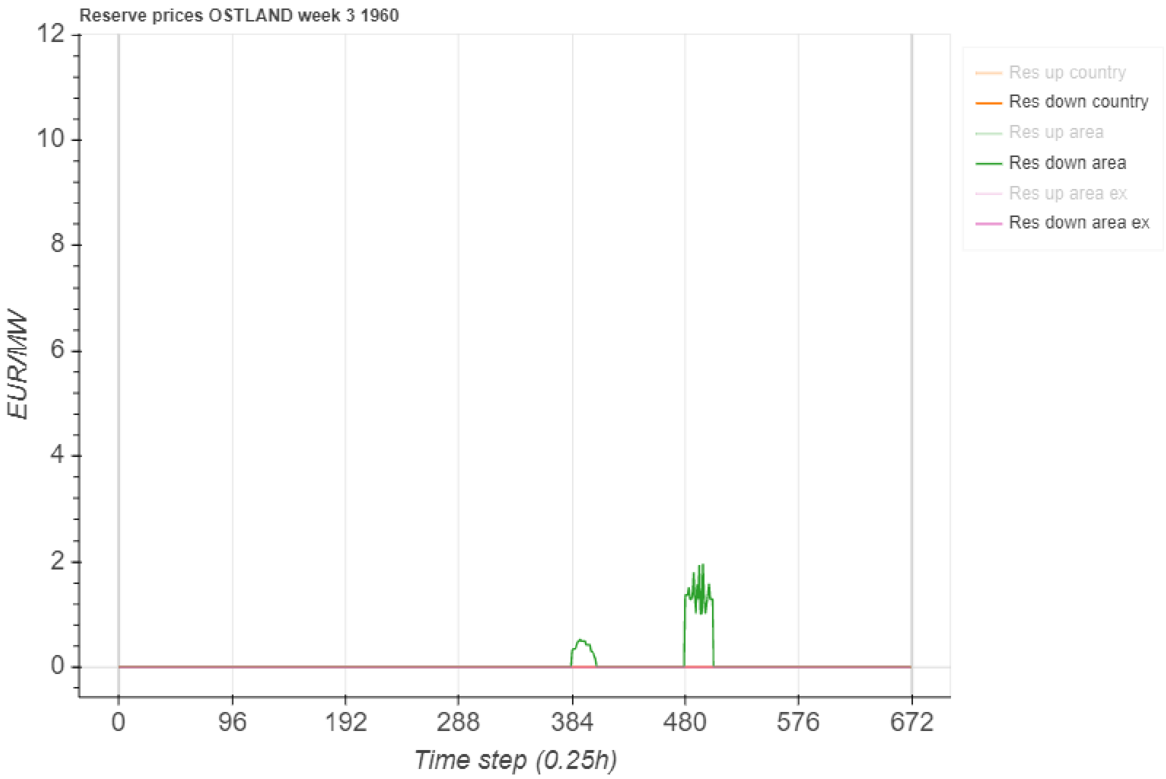

Figure 26 Plot of the dual value of the downward reserve capacity constraints in the country, area and area exchange case for week 3, weather year 1960.

5.1.2 Week 31 1989

Week 31 with weather data from 1989 has several periods with very low spot prices, as can be seen in

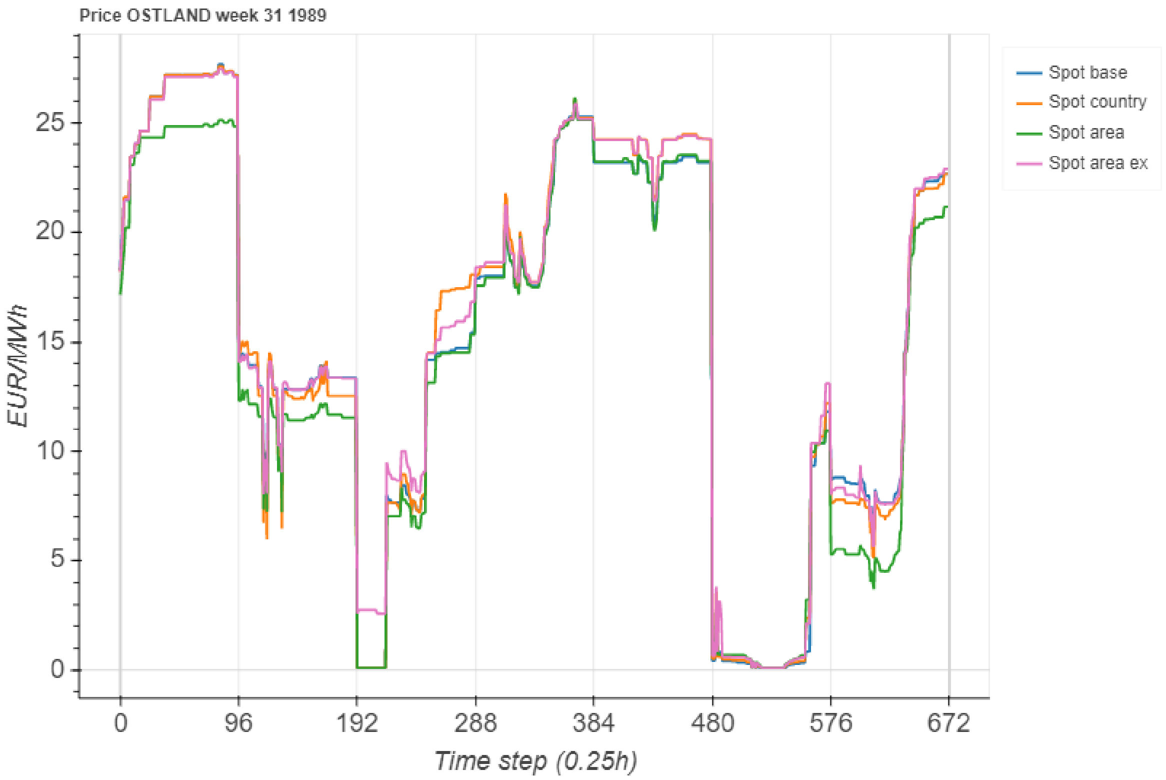

Figure 27 Simulated spot prices for week 31, weather year 1989. The prices are simulated using PriMod with no reserve capacity requirements (base), reserve capacity requirements per country (country), per price area (area) and per price area with exchange (area ex).. Summer weeks can often be caracterized by low consumption and high levels of unregulated production from solar, wind and/or hydropower. This give low spot prices. The average price is around 15 EUR/MWh, and this is the week in the analysis with the largest spot price differences between the cases. The spot price for the area case is on average more than 0.5-1 EUR/MWh lower than the other cases. This is due to the reserve capacity demands per area. In some areas, like Sver-midt in Sweden, power plants are forced to produce to cover the demand for downward reserve capacity. The effect is lower spot prices because more production comes from power plants that normally would not run, freeing capacity on cheaper plants and lowering the marginal cost of producing one more unit. Ostland imports more power from Sweden in the area case, lowering the spot price in Ostland.

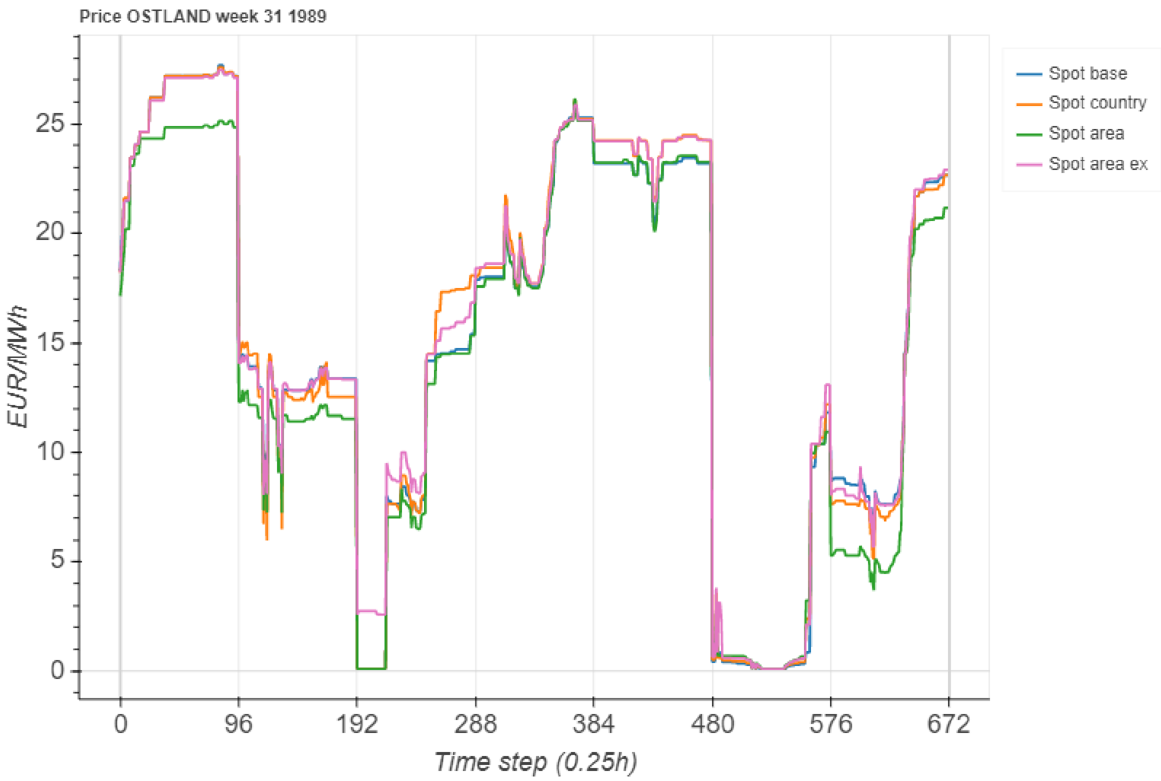

Figure 27 Simulated spot prices for week 31, weather year 1989. The prices are simulated using PriMod with no reserve capacity requirements (base), reserve capacity requirements per country (country), per price area (area) and per price area with exchange (area ex).

Figure 28 shows that there is a price for reserving upward capacity in all hours for the area case. There are several very small spikes on the upward reserve price in the two other reserve cases. In the area case, regulated power plants must always produce below optimal to be able to cover the reserve requirement for upward capacity. The price profile for upward reserve capacity is similar to the spot price profile. This is because the marginal cost of reserving one more unit of upward reserve capacity can reflect the cost of moving production from a power plant delivering upward reserve capacity to another power plant to free capacity for upward regulation. The marginal cost will then reflect the difference in cost of producing a unit of power at the power plant delivering reserve capacity and providing this production from another power plant. If the cost of producing at the power plant delivering reserve capacity is low, the cost of reserving one more unit of upward reserve capacity will be close to the marginal cost of producing one more unit, which is the spot price.

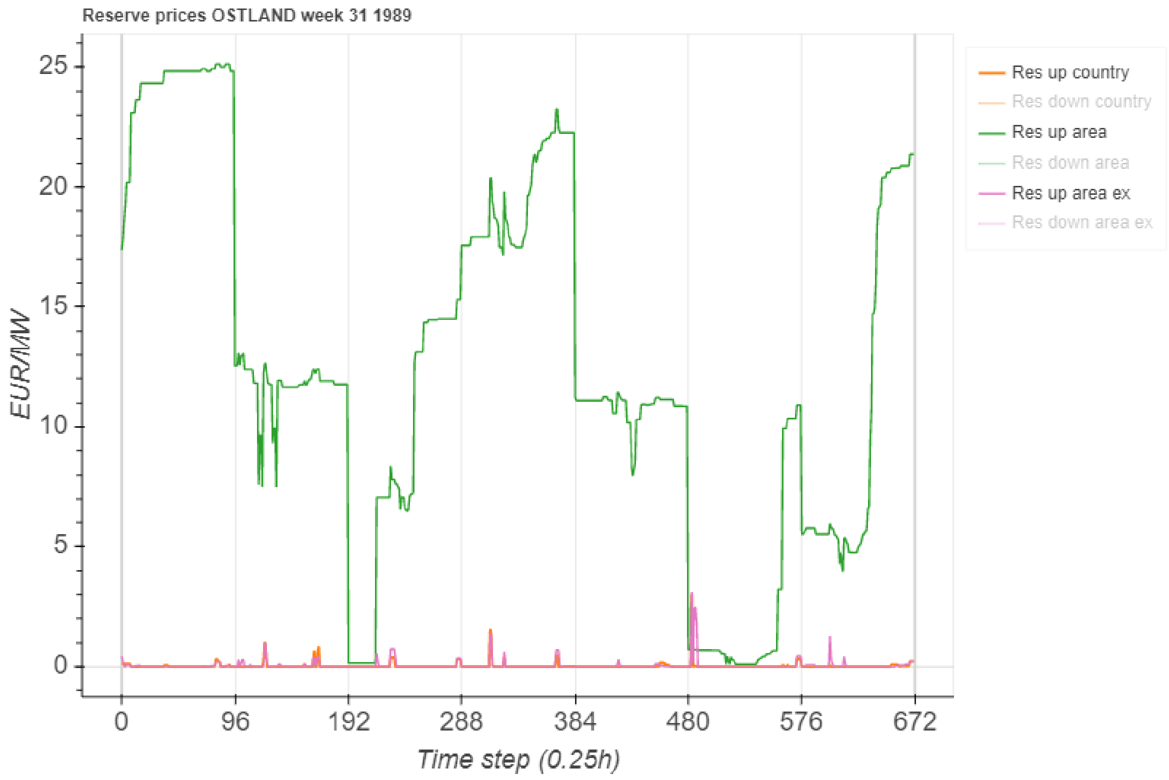

Figure 28 Plot of the dual value of the upward reserve capacity constraints in the country, area and area exchange case for week 31, weather year 1989.

Figure 29 reveals that there is no price for reserving downward reserve capacity in week 31 in 1989. 1989 is the wet year with high inflow and lower water values, so the production in Ostland will be high enough to deliver downward reserve capacity with no cost.

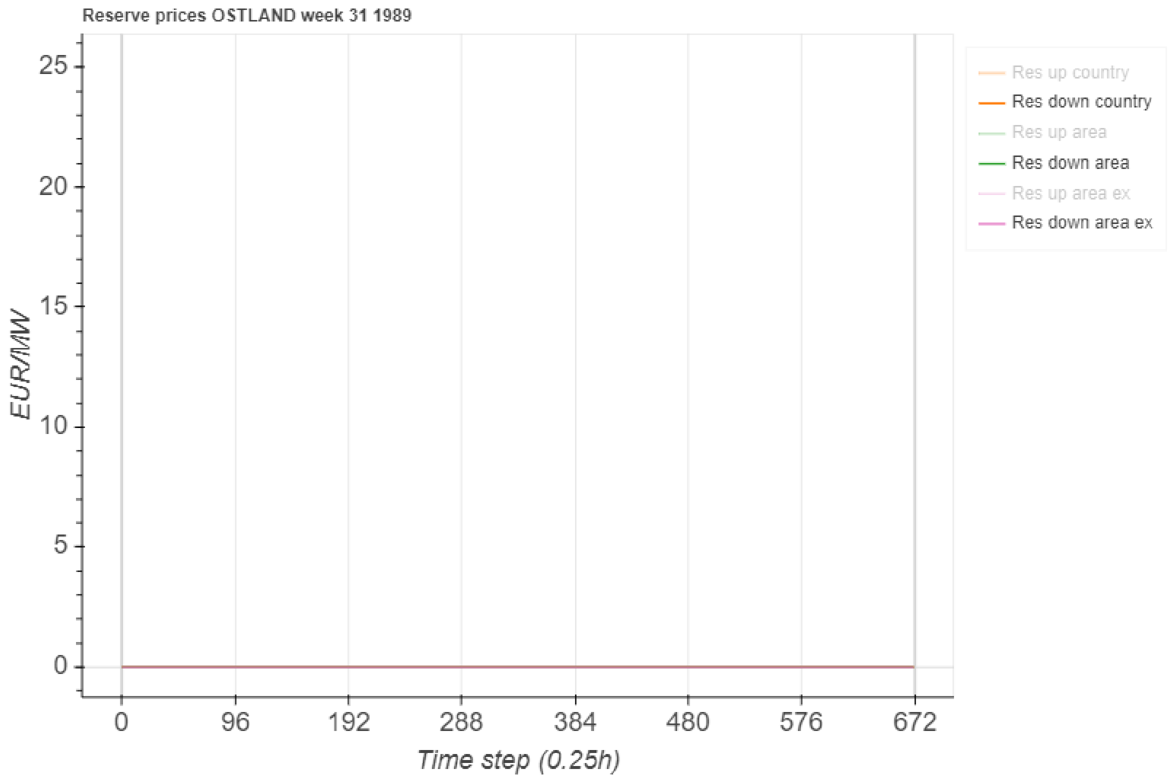

Figure 29 Plot of the dual value of the downward reserve capacity constraints in the country, area and area exchange case for week 31, weather year 1989.

5.1.3 Week 21 2009

Week 21 with weather data from 2009 has stable spot prices around 40 EUR/MWh during the week, but very low prices during the weekend, especially on Sunday. The results for all the four cases are presented in Figure 30. Comparing the cases, the spot prices are very similar but marginally lower in the case with reserve requirements per area, the most restricted case. In this week the spot prices are very low during the weekend and we see that the spot prices in the area case is lower than in the other cases. This might be because all the required reserve capacity for Ostland is reserved in Ostland on regulated power plants that would otherwise not produce. We see this because we have a reserve price, and because the total power production is Ostland is higher than in the other cases. Imports are correspondingly lower. To provide an extra MWh in this case is therefore cheaper because you can increase the production on a cheaper plant or import cheaper power.

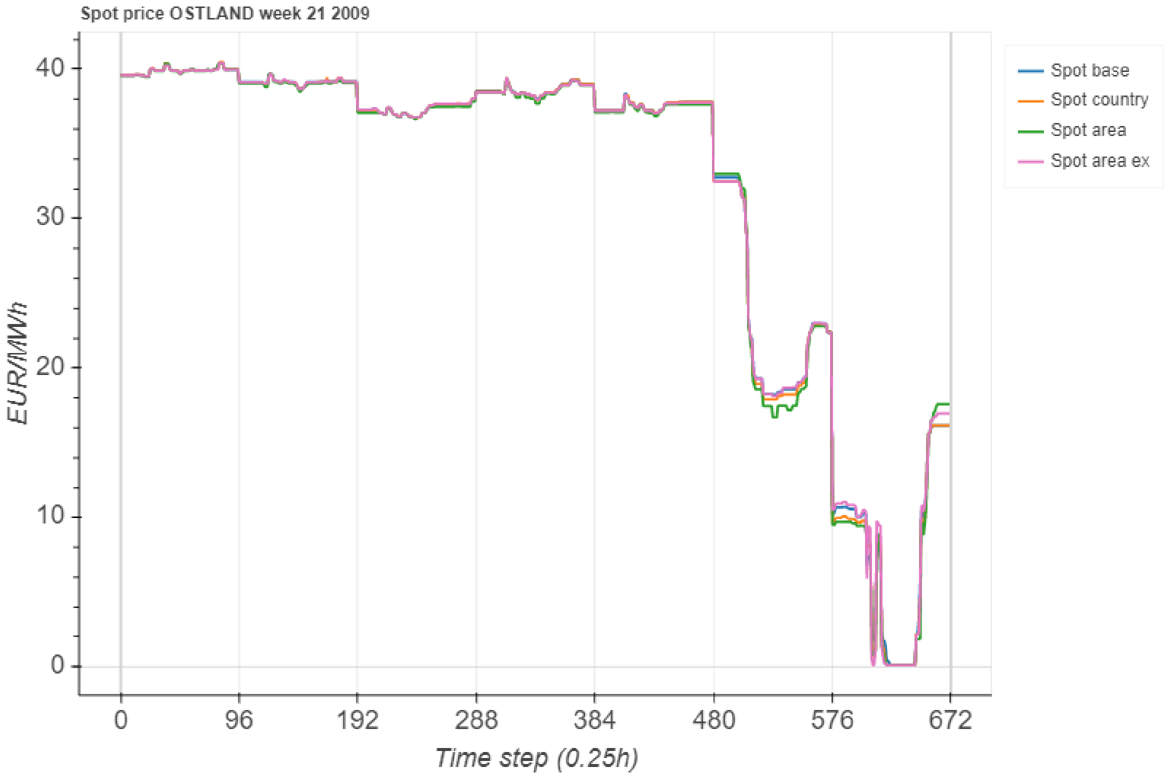

Figure 30 Simulated spot prices for week 21, weather year 2009. The prices are simulated using PriMod with no reserve capacity requirements (base), reserve capacity requirements per country (country), per price area (area) and per price area with exchange (area ex).

For week 21 the results presented in Figure 31 and Figure 32 show upward and downward reserve capacity prices for all cases. As for the other weeks, the prices are highest in the area case, followed by the area exchange case. The reserve prices are lowest in the case with a national market because reserves can be allocated where they are cheapest if there is no limiting gridflows. The reserve prices are highest during the weekend when spot prices are low. This is because hydropower plants in Ostland must produce more to be able to deliver the required amount of both upward and downward reserve capacity. Remember that this is spinning reserves, so to be able to deliver upward reserve capacity the power plant must be running at least at minimum capacity, and to deliver downward capacity they must produce above minimum production.

It is more expensive to reserve one more unit of downward capacity than upward capacity (the price for downward reserve capacity is higher). This might be because delivering one more unit of downward capacity by producing one more unit of power from a regulated power plant with high water value in Ostland is costly and will probably come in addition to production that is nearly for free because the "expensive" production must run to provide reserve capacity. The production also needs to be above a minimum level (the minimum production times the relaxed binary variable), so to deliver one more unit of downward capacity, the production sometimes must be increased by more than one unit (and lead to startup costs). This gives a high downward capacity price. Delivering one more unit of upward reserve capacity in this case, can be cheaper because this can be done by reducing production on the most expensive unit (producing to deliver downward capacity), and increasing production on a slightly more expensive unit to provide the downward capacity. This will only shift production from an expensive unit to a slightly more expensive unit, and lead to a smaller cost for providing more upward capacity.

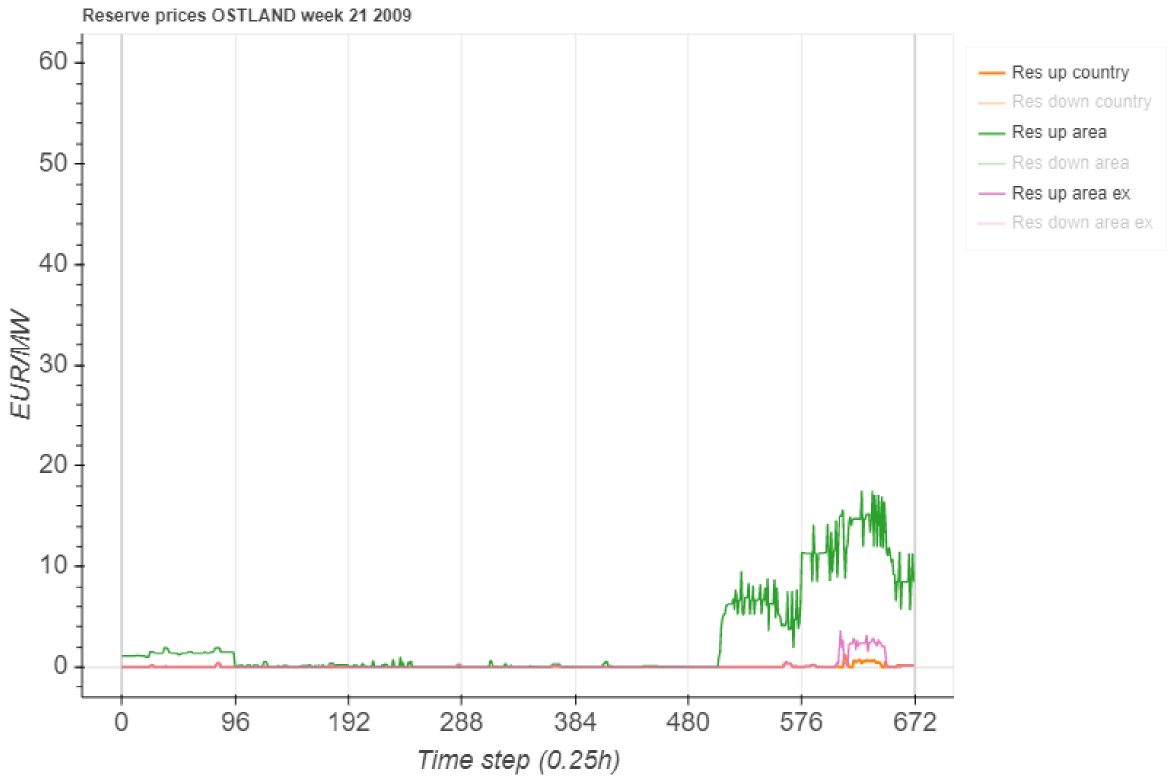

Figure 31 Plot of the dual value of the upward reserve capacity constraints in the country, area and area exchange case for week 21, weather year 2009.

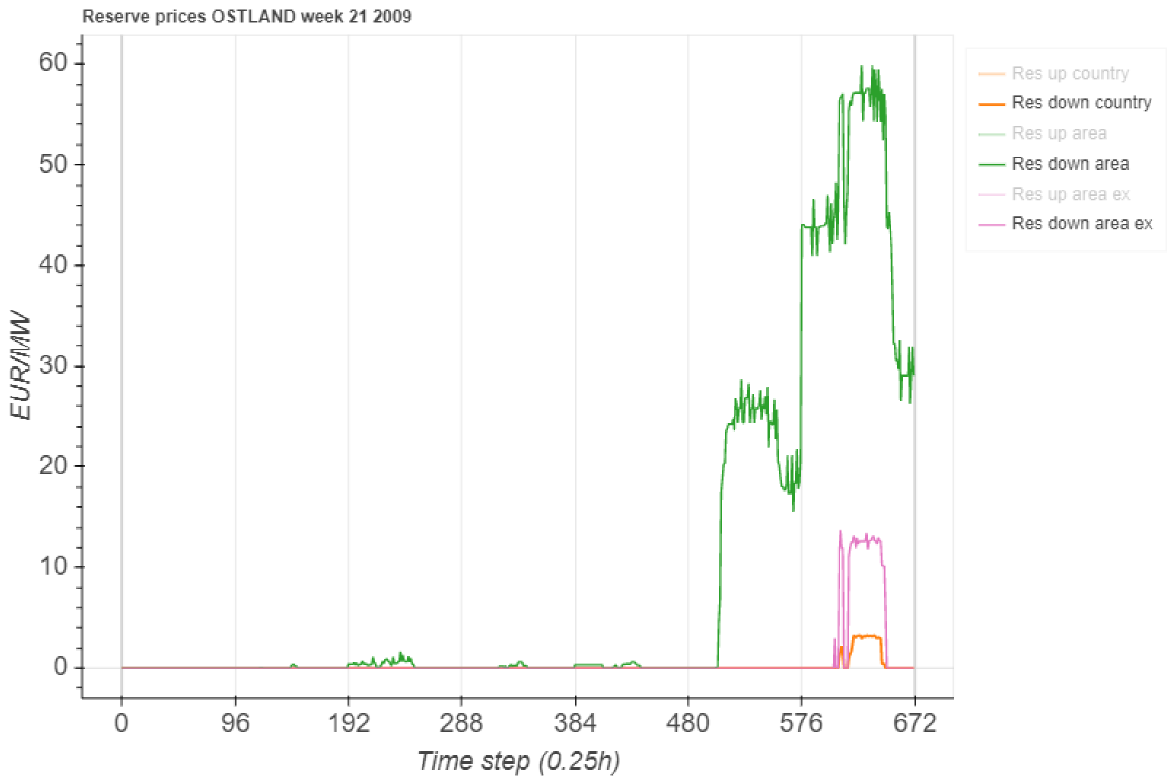

Figure 32 Plot of the dual value of the downward reserve capacity constraints in the country, area and area exchange case for week 21, weather year 2009.

5.1.4 Week 50 2009

Week 50 with weather data from 2009 has high spot prices, 46 EUR/MWh on average. The price profiles for this week can be seen in Figure 33. Comparing the cases, the spot prices are quite similar, but the area case has the highest peak prices. This is due to the requirement for upward reserve capacity.

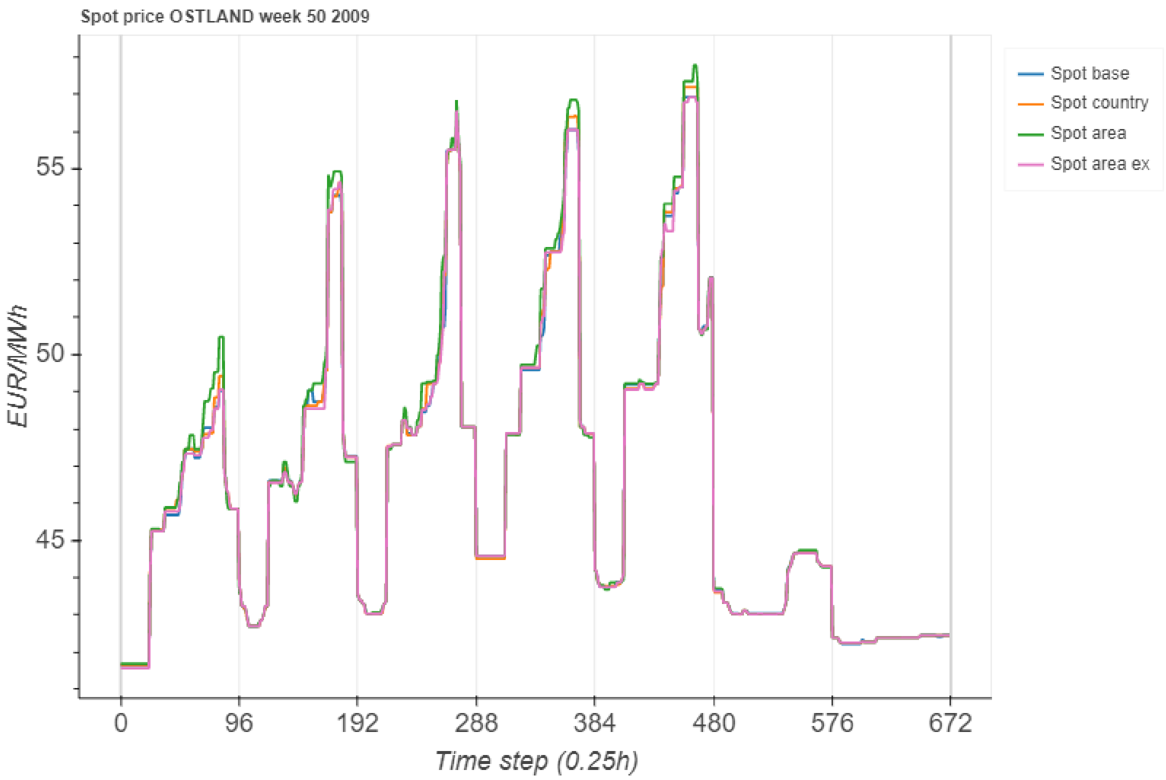

Figure 33 Simulated spot prices for week 50, weather year 2009. The prices are simulated using PriMod with no reserve capacity requirements (base), reserve capacity requirements per country (country), per price area (area) and per price area with exchange (area ex).

Figure 34 and Figure 35 shows the prices for procuring upward and downward reserve capacity in the different cases for week 50. When the spot prices are high, the cost of procuring upward regulation capacity is unequal to zero. Hydropower plants must produce at a lower level than their optimal to provide enough upward capacity, even if their water value is lower than the spot price. The upward reserve prices are highest in the area case where more upward reserve capacity is reserved within the area. There is no price of providing downward capacity because this is a winter week with high production and consumption, and there is enough available capacity to regulate down if something unexpected happens.

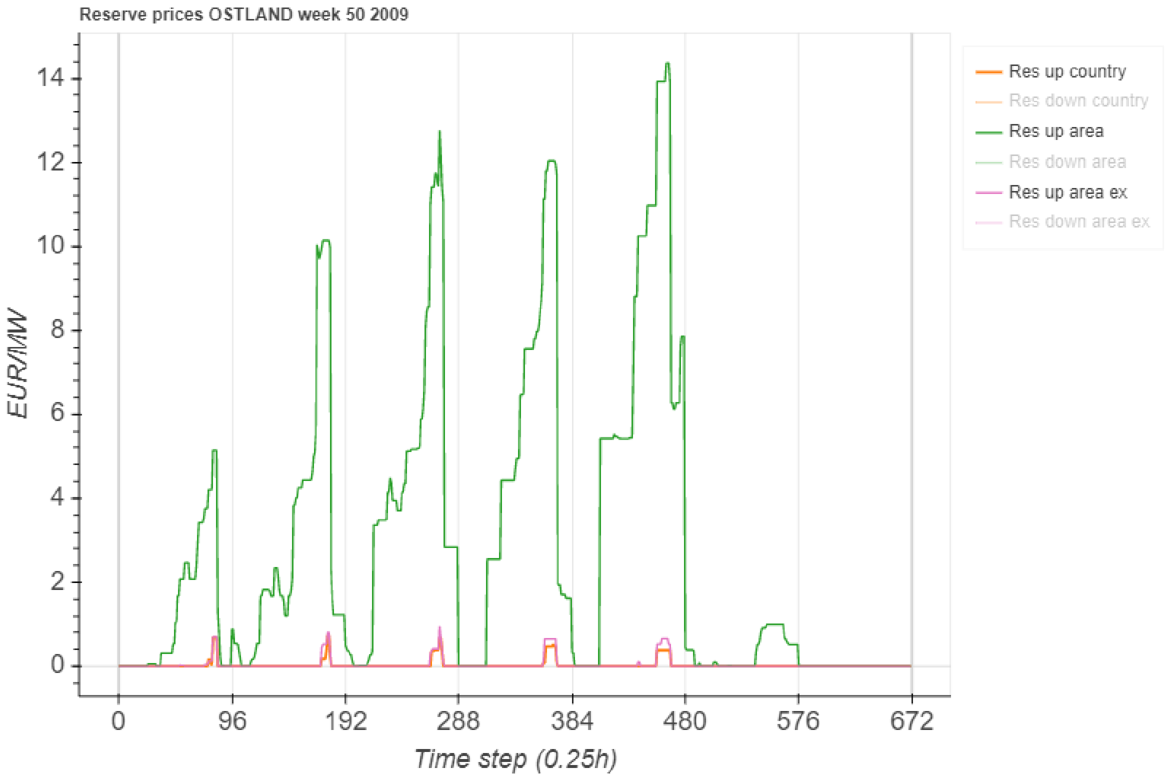

Figure 34 Plot of the dual value of the upward reserve capacity constraints in the country, area and area exchange case for week 50, weather year 2009.

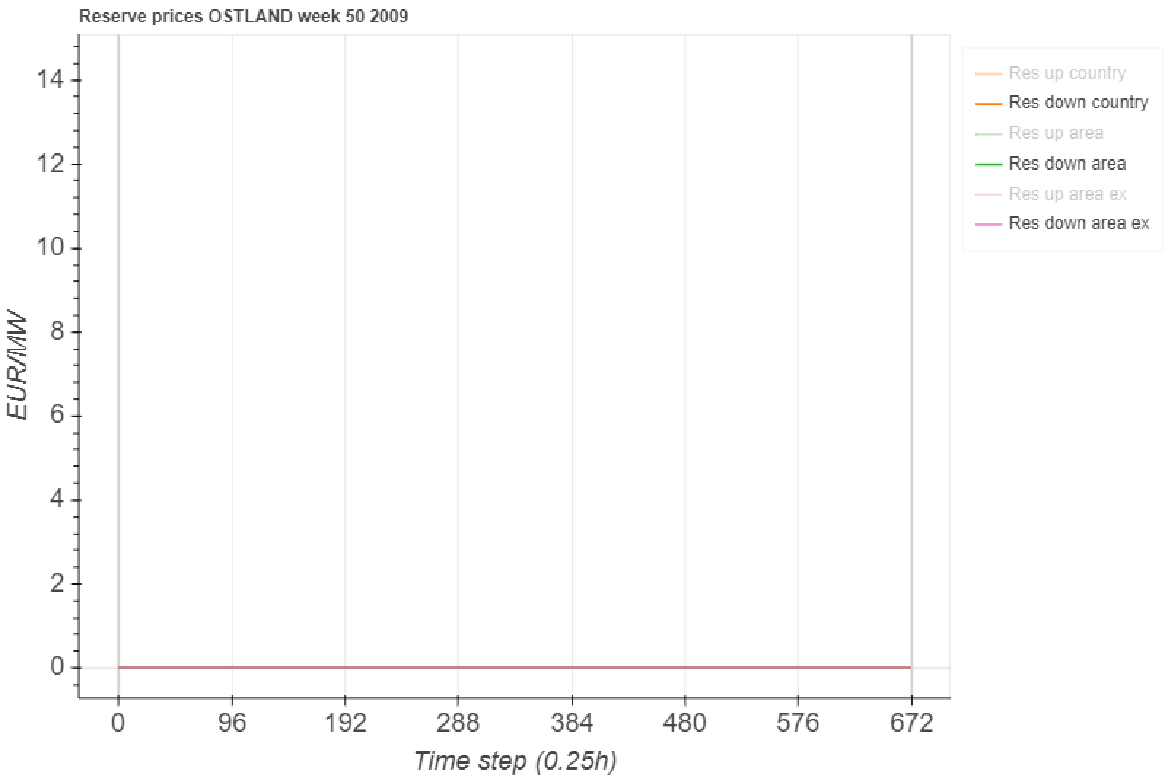

Figure 35 Plot of the dual value of the downward reserve capacity constraints in the country, area and area exchange case for week 50, weather year 2009.

5.2 Challenges

It is important to highlight that PriMod only considers the cost of procuring the reserve capacity. The effects of the reserve capacity being activated are not considered in the model (e.g. that there is available water in the reservoirs to regulate up the production, or if ramping down production will lead to flooding or violation of some minimum discharge requirements). If this was included, the distribution of reserved capacity among the power plants and costs might be different.

For week 3 in 1960, we used the initial reservoirs and strategy obtained from the EMPSW country case for all cases in PriMod. The same was done for week 31 in 1989. For the simulated weeks in 2009, the initial reservoirs and strategy was obtained from the EMPSW results from the corresponding case (i.e. EMPSW simulations with the area case was used to provide input to simulations of the area case in PriMod, etc). The EMPSW results from the area case was used for both the area and area exchange case in PriMod. If the reserve capacity constraint is binding for a hydro reservoir in EMPSW, the strategy/water value and reservoir trajectory for this reservoir can be different.This means that the initial reservoirs and the hydropower strategy was slightly different between the cases, and this can explain some of the differences in the PriMod results for week 21 and 50. However, since we also see differences between the cases for week 3 and 31, where the initial reservoirs and hydropower strategy was the same across cases, the price differences seen for week 21 and 50 in 2009 is mostly explained by the difference in reserve capacity constraints.

6 Comparison of spot price

This section will briefly compare the spot price results between the models. As explained in section, a comparison between EMPS V9 and EMPS V10 is not reasonable because of differences in the demand. However, EMPSW builds on EMPS V10, and has no temperature adjustment of demand, like EMPS V10. PriMod builds on EMPSW. So, a comparison of the spot price results between EMPS V10, EMPSW and PriMod can be done. EMPS V10 was only run for the country case, so here we compare the country case for the selected weeks between EMPS V10, EMPSW and PriMod.

The results for all four weeks are presented in Figure 36. The fact that EMPSW has a formal optimized disaggregation while EMPS is based on heuristics will lead to more price variation in the results from EMPS. EMPSW is better at utilizing the flexibility in the reservoirs. This can clearly be seen from the results, where the spot prices from EMPS V10 has a greater variation.

Remember also that EMPSW was run with initial reservoirs for the three selected weather years from the EMPS V9 results, and not the EMPS V10 results, so there might be some differences in the reservoir fillings between the results from EMPS V10 and EMPSW. To make the best possible comparison, initial reservoirs from EMPS V10 should have been used. Even though the year would have started with the same filling, the reservoir development throughout the year can deviate and accumulate between the models and result in different reservoir fillings and strategy for the chosen weeks. The initial reservoirs provided from the EMPS results to EMPSW was also only on an aggregated area level. If the average percentage filling in Ostland was 60 % from the EMPS results, all individual reservoirs in Ostland would get a 60 % start filling in EMPSW. The distribution of the water between the reservoirs in each area would therefore not be the same between the models. This led to a loss of information between the models, and ideally the individual reservoir fillings should have been transferred. However, this would have been more time consuming and was not prioritised in this work. This is something that can explain some of the difference we see in the spot price.

The results for week 21 and week 50 in 2009 are best suited for comparison between EMPSW and PriMod. This is because the initial reservoirs and water values used in PriMod for the different cases was obtained from the EMPSW results for the same case, ensuring as much equality as possible between the models. While for the two other weeks, only the results from EMPSW country case was used on in the PriMod simulations. In the comparison done here, all results shown are for the country case, making the basis for comparison similar between the weeks. Differences in the modelling can explain differences between the spot price results from EMPSW and PriMod. EMPSW optimizes the whole week-problem as one, while PriMod splits the week problem into days, optimizing one day at a time with an end-valuation of water based on the water values for the end of the previous week and the end of the current week as explained in section 1.1.3. This can lead to a different usage of water than in the EMPSW, influencing the spot prices.

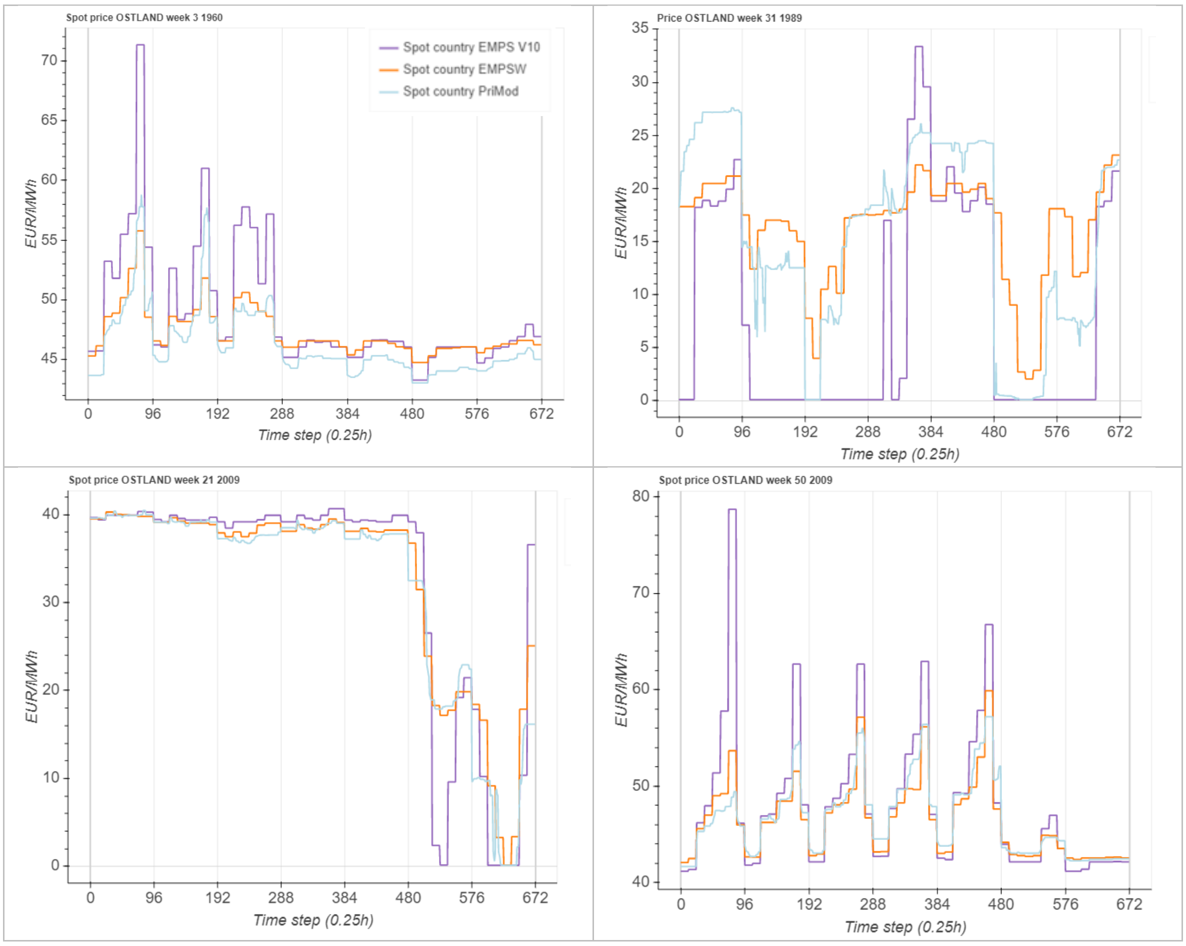

Figure 36 Comparison of the spot price results from EMPS V10, EMPSW and PriMod for the country case for week 3 1960, week 31 1989, week 21 and 50 2009.

7 Concluding remarks

We have in this study used a wide range of models and functionality to analyse the consequences of reserve capacity requirements in power system modelling. The results from the different models have been discussed above. Based on the results, the PriMod model provides the best functionality for evaluating the impact of reserve capacity constraints and prices for these types of services in hydro dominated areas. However, the PriMod model requires input from long-term hydropower models, such as EMPSW or FANSI. The reserve capacity functionality in EMPS was found to be of limited usefulness to evaluate prices for providing reserve capacity in hydropower dominated areas. The aggregate hydro model represents too large flexibility. Still, the functionality is useful for areas with limited hydro production to get an impression of the available flexibility in areas with high share of hydropower. Further, EMPS can be used to select weeks for detailed analysis in PriMod and it was shown that there were some small changes in the resulting spot price in EMPS when including reserve capacity requirements.

An important challenge when simulating prices for future systems are the reference prices, or costs taken as inputs to the model. The prices in hydro dominated areas are strongly impacted by the value of storing water, the water value, which again depends on the future expectations for the power price. Traditionally, thermal power production – and associated fuel costs – have been the most important reference costs. The transitioning of the power system is giving more hours where such units are not producing or where there might be a deficit of capacity. As a result, there are more hours where the price is set by the extremes, namely flooding and rationing. A similar behaviour can be observed in the resulting prices for procuring reserve capacity in the EMPS model. This implies that the price setting in the extremes is becoming more important as well as the probabilities of ending up in the extreme scenarios.

The runs using PriMod gave interesting spot price and reserve price results. PriMod illustrates the complexity in evaluating prices for providing reserve capacity and the associated impact on the spot price. Prices for reserve capacity are highest when the system is operated at the extremes, either with a high surplus of energy or a deficit of energy. The impact on the spot price, however, can give both higher and/or lower prices in periods. The results also illustrated the importance of the geographical region the reserve requirements are defined over and if exchange of reserves is allowed or not. The model has a promising potential for assessing different cases for reserve requirements, both levels and designs, and to evaluate the use of the transmission capacity for exchange of reserve capacity.

The study shows how several models can be used together. We have made important experiences related to how the models are linked, and the type of data sent between models. If the goal is to compare different cases for reserve capacity, the input (water values and reservoir fillings) to PriMod should be the same for all cases, to eliminate additional sources of differences in the results. In such a study, a strategy (water values) calculated for one of the cases (e.g. base) and reservoir levels from the same simulation could be used as input (from EMPSW/FANSI). If the focus is to compare price results between models, the input should be "strictly following one case" to eliminate other sources of differences. In such a study, the strategy and reservoir filling from a simulation of each case in EMPSW/FANSI should be taken as input to each according case in PriMod. This will contribute to reduce the sources that can cause differences between the cases in the study. Still, the results from this study also show that the small differences in strategies and reservoir fillings only have minor effects on the results. It is of higher importance that the strategy is calculated for the same dataset with the same functionality (e.g. with or without temperature correction), and that the start fillings are from the correct year, week and reservoir. The impact on the results from using a start filling from a different case into a case in PriMod is minor compared to the differences seen from changing the case in PriMod (i.e. the reserve capacity requirements).

The study had some weaknesses. Some unwanted differences between the model runs were discovered during the work, such as the difference in use of temperature correction between version 9 and 10 of EMPS. This made it inappropriate to compare results from the first part of the study with the second part. Furthermore, some smaller adjustments to the method were made on the way, such as using EMPSW results from the corresponding case as input to the PriMod simulations. In addition, all model runs after EMPS (v10) are based on the aggregated strategy from EMPS from one run. This implies that effects of changing reserve capacity requirements on the aggregated strategy are not included. The effect of capacity prices on water values is discussed in [13]. The Fansi model is the only model in the existing portfolio of market models that have possibility to include reserve capacity constraints in the long-term strategy evaluation.

In general, there is very little impact of reserve constraints, only in the most detailed model PriBas in the week with the highest load results with a significant impact from the reserve constraint is documented.

It is logical that the stressed system will have larger impact from reserve requirements and that the details in the modelling will have impact on the ability to calculate realistic procurement cost.

Further work will include using binary variables to improve hydro system modelling. With linearized startup cost the non-convexity of the production curves are not included and it is just as cheap to start two power plants at 50% of best efficiency as starting one at 100% of best efficiency.

There are different reserve products where provision of primary reserve has ability to go beyond the long-term limits of the turbines and generations delivering 1.1 or 1.2 PU capacity for shorter periods. Efficiency curves will impact on the optimal static setting of the units in the power plants deciding what contribution a unit can make to reserves not merely that the unit is running.

This is a picture where modelling the constraints of the technologies in the power system will be very important for understanding the possibilities for providing flexibility from cascaded hydropower.

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