Impact on hydropower plant income from participating in reserve capacity markets

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***Abstract*—The aim of this work is to simulate prices in the markets for spot and spinning reserve capacity in the Nordic region. We consider four selected seasonal weeks using a model framework for multi-market price forecasting in hydro-thermal power systems. Five different cases for reserve capacity requirements are studied: no requirements, requirements per country or price area with or without the possibility to exchange reserves by reserving transmission capacity between regions. The realized income of specific hydropower plants participating in these markets was quantified for selected time periods, based on a 2030 scenario for the European power system. The results show that for certain plants, the income from participating in the reserve capacity market contributes with up to 54 % of total income under certain conditions.**

***Index Terms*--Hydro-Thermal Scheduling, Power Market Modeling, Electricity Price Forecasting, Reserve capacity.**

I. Introduction

In the transition towards a greener and more unified power system, increasing shares of variable renewable energy production and more exchange between countries will lead to higher need for reserve capacity to balance the energy system at all times [1]. Electricity prices in the physical markets are expected to become more volatile [2], which will have a significant impact on how the hydropower plants and reservoirs will be operated. In the Nordic countries, hydropower producers currently get most of their income from participating in the spot market [3]. In the future, it is likely that regulated hydropower plants operating in markets with high shares of variable renewable energy (VRE) to a larger extent adjust their schedules to be able to sell fast-responding reserves. Hence, to make good investment decisions for the future, producers will need consistent long-term price forecasts for multiple electricity products.

In this paper we simulate prices in the spot market and the market for spinning reserve capacity for four selected weeks. Work is in progress to harmonize energy and capacity markets across borders in Europe [4]. This development is represented in two of the five different cases for reserve capacity requirements studied here. The five cases are: no requirements, requirements per country or area with or without the possibility to exchange reserves by reserving transmission capacity between regions (for case matrix, see Table IV). The realized income of specific hydropower plants participating in these markets was quantified for the studied weeks and cases based on a 2030 scenario for the European power system.

The importance of modelling short-term aspects increase with the penetration of VRE and the tighter integration of the European power system [5]. Therefore, a fundamental hydro-thermal multi-market model, comprising a long-term strategic model and a more detailed short-term fundamental model, was used to perform the study. To our knowledge it is the first time such a modelling framework for the North- and West-European power system has been used to evaluate the future income potential from several markets for individual hydropower plants in the Nordic region.

Gebrekiros et al. [6] present a modeling approach for frequency restoration reserves (FRR) comprising three decision stages where reserve capacity and cross-border transmission capacity is allocated prior to the day-ahead market clearing. A case study of the Northern European power system show that the highest total cost-reduction occurs when around 20 % of the cross-border capacity is reserved for exchange of reserve capacity. Domínguez et al. [7] has explored three different scheduling models with reserve procurement before, after or simultaneously as the clearing of the day-ahead market in a renewable-dominated European power system, and found that a co-optimization of energy and reserves is the most efficient. The study demonstrated reduced operating costs of coordinated procurement of reserves by the TSOs. In this work, we focus on prices in the spot market and for procurement of reserves, as well as the income of hydropower plants. To simulate optimal operation and prices, a co-optimization of the day-ahead and spinning reserve capacity markets was used.

The modelling framework, scenario and case setup used in the case study are presented in section II. In section III and IV, the main results from the case study is presented and discussed. Finally, the paper is summarized and concluded in section V.

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II. Method

A. Modelling framework

In this study we simulate market prices for electricity and reserve capacity products by using a framework for long-term price forecasting in hydro-thermal power systems consisting of two modeling layers [8]. The stochastic long-term hydro-thermal scheduling (LTHTS) model described in [9] provides individual water values to an operational short-term model. The LTHTS model consider uncertainties in inflow, wind and solar power while using weekly decisions stages and time steps of 3 hours. A short-term hydro-thermal scheduling (STHTS) model is then used to re-optimize the weekly decision problem with a time resolution of 15 minutes, including more details, such as constraining thermal power production. For details on the thermal modelling in the STHTS model, see [10]. To reduce the increased computation time from adding more details, the STHTS model decomposes the weekly decision problem into daily sub-problems as elaborated in [10]. The STHTS model has a simultaneous clearing of the spot market and reserve capacity market.

Both models have a detailed physical modelling of the North-West European power system, including transmission corridors between regions. The two models both include a detailed description of the hydropower system in the Nordic area with cascaded water courses and characteristic such as storage and turbine capacity, efficiency curves and flow restrictions. Weather uncertainty is accounted for using historical records for inflow, wind and solar radiation for the period 1958-2009 in the LTHTS. Both models include functionality for reservation of upward and downward reserve capacity and ramping on HVDC cables, while the more detailed STHTS better captures the reserve capacity price formations and has functionality for cross-border exchange of reserve capacity.

In the STHTS model all hydropower plants delivering reserve capacity are represented by linearized start-up costs assuming a minimum production at 50 % of best efficiency discharge. The commitment status of the thermal units are also relaxed in the model, making it a linear problem, similar to [11]. The relaxation of discrete decisions was made to obtain dual values from the corresponding linear programming (LP) problem. In a LP problem, the dual values of the power balance constraints and the reserve requirement constraints equal the marginal costs of demanding more energy and reserve capacity, respectively. In this paper we use the terms spot price, and upward and downward reserve price for these marginal costs. Relaxing binary variables also reduced computation time. All computations were performed using CPLEX 12.7 as the optimization solver and an Intel Core i7-9850H processor with up to 2.60 GHz and 64 GB RAM. With this set-up, one daily problem was typically solved in 10-15 minutes.

B. Scenario description

The case study is done for a 2030 scenario of the European power system developed by SINTEF Energy Research [12], [13]. The system comprises 57 areas, with a high level of detail for the Nordic region. More than 1000 individual hydropower reservoirs are included in the model. The VRE capacities in the scenario is based on recent political targets and commitments in Europe [14].

C. Case description

In this study we analyse four different weeks with five different cases for requirements for spinning reserve capacity in the Nordic region. The LTHTS model was run for three different weather years: with low, high, and normal annual average for all inflow records. Four weeks, one from each season, was selected from these three years and re-optimized with the STHTS model, see Table I. For all weeks, initial reservoir volumes obtained from the LTHTS model were used as a starting point. These four weeks only show snapshots of the complete planning horizon, and in this study we will look at examples more than drawing general conclusions.

Table I Cases – Selected weeks.

Week number	***Weather year***	***Inflow***
3	1960	Low
31	1989	High
21	2009	Normal
50	2009	Normal

Five cases with different spinning reserve capacity configurations for the Nordic region are presented in this study, see Table II. In the two cases with exchange of reserves across country borders, 10 % of the transmission capacity was available for reservation. The Area case is the most restricted case, where each price area must fulfil their own demand, while the Country X case is the least constrained case with reserve requirements. The four selected weeks in Table I and the five cases for reserve requirements in Table II were combined into 20 different cases in total for this study.

Table II Cases – Handling of reserve requirement.

Case	**Description**
Base	No reserve requirements
Country	Reserve requirements per country
Country X	Reserve requirements per country with exchange of reserves across country borders
Area	Reserve requirements per price area
Area X	Reserve requirements per country with exchange of reserves across area borders

The reserve demand for spinning reserves include primary (FCR) and secondary (aFRR) reserves and is based on the current reserve demand in the Nordic countries and plans for expanding and increasing the demand in these markets. This includes doubling the current demand for aFRR, from 300 to 600 MW [15]. The current market demand for normal primary reserves (FCR-N) is 600 MW. There is also a demand for upward FCR-D capacity due to the largest dimensioning fault in the Nordic synchronous system being 1200 MW. The demand for FCR-N and upward FCR-D is assumed to be on todays level. In few years, new interconnectors from Norway

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to Great Britain and Germany will come into operation and a market for downward FCR-D of 1200 MW will be introduced [16]. Since the model data and time resolution is not fine enough to separate between the different types of spinning reserves, the above-mentioned requirements are merged. An allocation key is used to divide the demand between countries and price zones. The total requirement for spinning reserves used in the study can be seen in Table III.

Table III The demands for spinning reserve capacity used in the analysis.

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

All hydropower plants with reservoir capacity larger than 1.0 Mm^3 can provide reserve capacity in the STHTS model. In the price areas SE3, SE4, DK2 and FIN, mainly gas-fired power plants are selected to deliver reserve capacity, in addition to hydropower. In DK2, thermal plants are the only reserve capacity provider.

When comparing the income from participating in different markets for selected hydropower plants, we look at the share of total income coming from the different markets and not the total income. Different use of water in the different cases and the valuation of this water need to be accounted for when comparing total income between cases. The total income is also affected by the prices obtained in the markets, which we will see vary between cases.

III. Results

A. Spot prices

The spot price results for the modelled area resembling the Nordic spot market area NO1 for all four selected weeks are presented in Fig. 1. Only the Base case and the Area case is shown. NO1 has a high demand for reserve capacity while being the area in Norway with the highest demand for energy and is therefore the main focus in the following. There are only small differences between the cases for the spot prices in week 3, 21 and 50. The Area case has slightly higher price spikes in week 3 and 50. In strained situations, the reservation of upward reserve capacity will often lead to higher spot prices. In week 31 and for the weekend in week 21, the spot prices for the Area case is notably lower. In periods with low spot prices, production can be shifted from power plants with low marginal cost to power plants with higher marginal costs to fulfil the reserve capacity demands in the model, lowering the marginal cost of producing one more unit (the spot price).

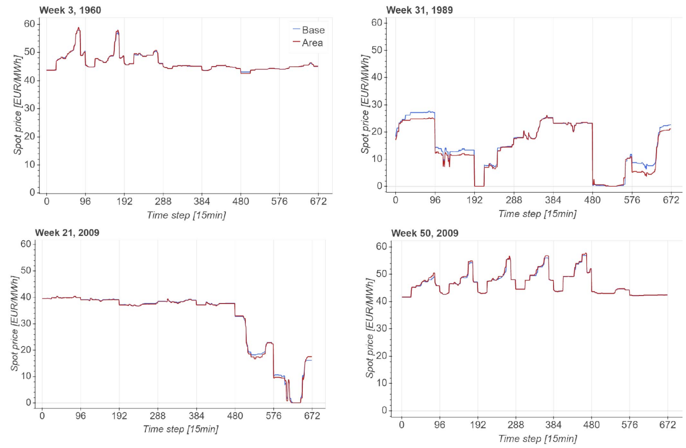

Fig. 1 Spot prices (EUR/MWh) in NO1 for all weeks. The results show the Base case and the Area case.

The average spot prices for the NO1 area for all weeks and cases are shown in Table IV. We see that the impact on the spot price from including reserve capacity constraints in the different cases can give both higher and lower spot prices. If there is a cost of procuring reserves in a time step there will normally be an impact on the spot price. Reserve capacity can to a certain extent in some water courses be provided as a by-product at little additional cost, such as for a generator running at best efficiency point with available capacity for both up- and down-regulation. There will however be a threshold for capacity supply, after which further sales of capacity more severely impacts system operation, and therefore is associated with a higher cost. This is the case whenever sales of capacity lead to a different optimal generation schedule than would otherwise have been found in the energy-only case. In such cases there is a lost revenue in the energy market (representing the opportunity cost). Furthermore, since the problem is dynamic, requiring reserves can give a different use of water and a deviation in the reservoir filling over time. This can again have an impact on the spot price also in following time steps. The effect on the spot price in one price area can also affect the spot price in other price areas.

Table IV Average spot price in NO1 for all weeks and cases (EUR/MWh).

Week \ Case	Base	Country	Country X	Area	Area X
3	46.18	46.19	46.16	46.19	46.20
31	15.25	15.46	14.62	14.39	15.66
21	32.00	31.93	31.92	31.84	32.00
50	46.56	46.58	46.41	46.70	46.55

B. Reserve capacity prices

The upward spinning reserve capacity prices for NO1 for all cases with reserve capacity (Country, Country X, Area, Area X) are presented in Fig. 2.

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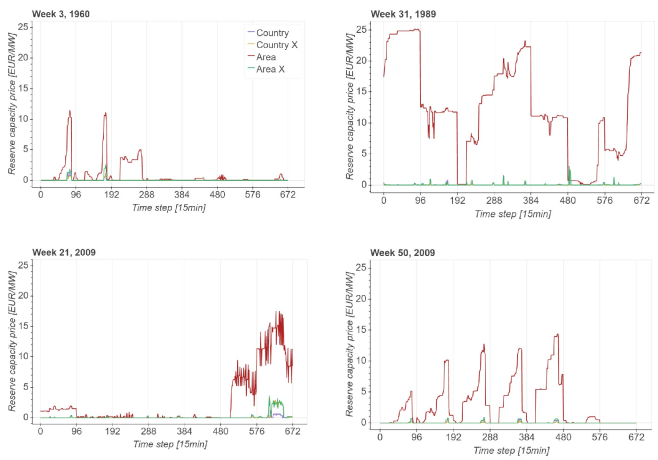

Fig. 2 Prices for upward reserve capacity (EUR/MW) in NO1 for all weeks. The results show the Country, Country X, Area and Area X case.

For all studied weeks, there is an upward reserve capacity price in NO1 in the Area case, the highest price is 25 EUR/MW. The price mainly follows the spot price spikes. NO1 is dominated by unregulated (run-of-river) hydropower production and is a net importer. When spot prices are high, power plants are forced to hold back production to deliver upward reserve capacity, leading to a significant price of reserving this capacity. In the Country, Country X and Area X cases, the reserve capacity prices are significantly reduced in this area. In other price areas with more regulated hydropower production, the reserve prices increase when exchange of reserve capacity between areas or country is allowed, leading to a higher share of reserve capacity provided from these areas. See Fig. 5 and Fig. 6 in the Appendix for reserve capacity prices for upward and downward reserve capacity in week 21 for price area NO5.

The price for reserving downward spinning reserve capacity is only non-zero in NO1 in week 3 for the Area case and for all cases in week 21. The downward spinning reserve capacity prices for NO1 for week 21 are presented in Fig. 3.

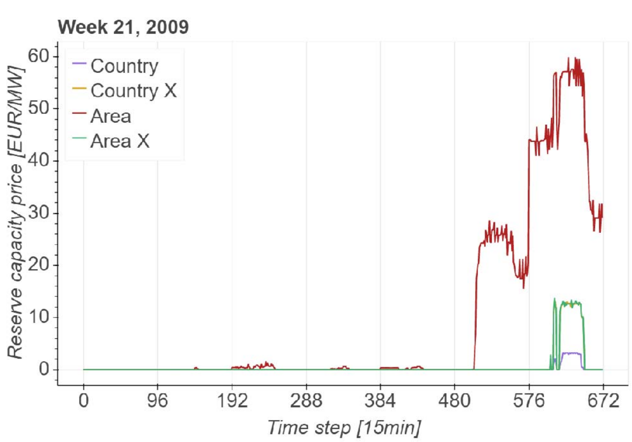

Fig. 3 Prices for downward reserve capacity (EUR/MW) in NO1 for week 21. The results show the Country, Country X, Area and Area X case.

When the spot price drop towards zero in the weekend, the price for reserving downward capacity increases, especially in the Area case. In periods with high VRE-penetration, reserve capacity providers that normally would shut down are forced to produce to fulfil the reserve demand, leading to reserve capacity prices for both upward and downward reserve capacity. In week 3, the downward reserve price in NO1 is low, and only occurs at night when the spot price is lower due to lower production. The lack of a price for reserving downward capacity in week 31 can indicate that we have too many reserve capacity providers in our model.

C. Hydropower plant income

Fig. 4 show the total income from the spot market and the reserve capacity market for upward and downward reserve capacity respectively, for all hydropower plants delivering reserve capacity in NO1 in week 21 for the Area case. The income level is strongly related to the production of the hydropower plant, and the distribution of income for smaller power plants is better captured from the percentage shares in Fig. 7 in the Appendix. The plants are sorted from low to high degree of regulation (a measure of the storage capacity relative to average annual inflow). One could expect hydropower plants with higher degree of regulation to provide most of the reserve capacity, but in this spring-week with relatively low power prices and high inflow, the better regulated power plants can limit their production and mainly deliver upward capacity. An example is plant number 21 which has a higher production capacity than number 2 but has much lower production (and therefore income). Number 21 mainly delivers upward capacity, while number 2 has a high production, and mainly delivers downward capacity.

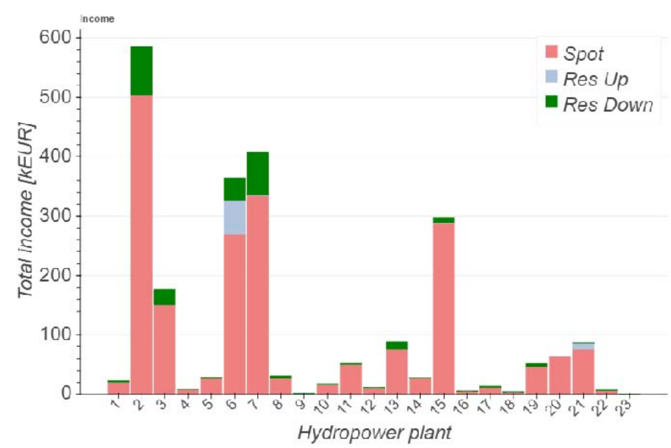

Fig. 4 Income (kEUR) from the different markets for hydropower plants delivering reserve capacity in NO1 for the Area case in week 21.

Table V show characteristics of a selection of hydropower plants in different price areas; NO2, NO5, NO1 and SE1. The power plants span a wide range of production and storage capacity.

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Table V Characteristics of hydropower plants selected in the study.

Plant	Price area	Production capacity (MW)	Reservoir capacity (Mm3)	Degree of regulation (%)
Saurdal	NO2	640	3105	309
Kvilldal	NO2	1240	238	21
Suldal 2	NO2	150	2	0.5
Aurland 3	NO5	270	448	310
Duge	NO2	200	1398	298
Nedre Vinstra	NO1	308	31	10
Rendalen	NO1	100	1	0.1
Øvre Vinstra	NO1	140	84	60
Porjus	SE1	480	610	47

Table VI show the largest obtained share of income coming from the reserve capacity markets for each hydropower plant, and for which week and case this share is achieved.

Table VI The week and case with the highest share of total income provided from the reserve capacity markets for the selected plants.

Plant	Highest share (%)	Week	Case
Saurdal	6.5	31	Area X
Kvilldal	4.8	21	Area X
Suldal 2	1.1	21	Area
Aurland 3	0.64	31	Area X
Duge	0.13	31	Area X
Nedre Vinstra	26.2	21	Area
Rendalen	13.9	21	Area
Øvre Vinstra	11.6	21	Area
Porjus	0.17	31	Country

Due to the different characteristics and location of the hydropower plants, the impact on income from the different cases for reserve requirements varies. For all plants, the relative income from selling reserve capacity is highest in the weeks when spot prices are lower. In NO2 and NO5 the upward reserve capacity prices are often highest in the Area X case. Saurdal, Kvilldal, Duge (all in NO2) and Aurland 3 (NO5) get the highest share of their income from the reserve markets in the Area X case by selling upward reserve capacity. Suldal 2 (also in NO2) has a low degree of regulation and sell downward capacity. The downward reserve capacity price is highest in NO2 in the Area case. All reserve capacity prices are highest in NO1 in the Area case, leading to a high share of income from these markets in this case. SE1 has highest reserve capacity prices in the Country case, and the region can then provide reserve capacity to the rest of the country, leading to higher income.

Looking at the four selected price areas, also other hydropower plants than the selected ones have high shares of income from the reserve markets. Table VII show that for these four price areas, the income from participating in reserve capacity markets go up to 53.9 % of total income for certain power plants. Hydropower plants in NO2 and NO5 get a higher share of their income from participating in reserve capacity markets in cases with exchange of reserve capacity. Even though the reserve capacity price is not always highest in these cases, a higher amount of reserves can be provided from these surplus areas compared to the Area case.

Table VII The highest share of total income coming from reserve capacity markets obtained by a hydropower plant in selected price areas.

	Highest share (%)			
	Week 3	Week 31	Week 21	Week 50
NO1	2.0 (Area)	53.9 (Area)	26.2 (Area)	7.0 (Area)
NO2	0.3 (Country X)	6.5 (Area X)	5.0 (Country X)	0.2 (Area X)
NO5	1.1 (Area X)	0.6 (Area X)	3.6 (Country X)	0.3 (Area X)
SE1	3.0 (Country)	41.1 (Country)	1.3 (Area X)	2.2 (Country)

IV. DISCUSSION

The results show that allowing reserve sharing between price areas significantly reduce the reserve capacity prices in deficit areas. This is in line with previous studies showing a cost-reduction when cross-border capacity is allocated for reserve sharing. In cases with more reserve sharing, the income potential for hydropower plants delivering reserve capacity in deficit areas is also lower, while the income potential for plants in surplus areas can increase.

Reserve capacity providers must pass a prequalification to be able to deliver fast responding reserves in the future [16]. A better selection criterion for reserve capacity providers in the model can lead to more realistic simulated reserve capacity prices. There is also uncertainty about the magnitude of demands for reserve capacity in 2030, and our conservative assumptions might be too low. Moreover, there is a potential of adding more details to limit the flexibility of hydropower, e.g., by improving the production function (PQ-curve) and adding ramping constraints on discharge. Especially, the minimum, optimal and maximum production levels of the hydropower PQ-curves can have large impacts on the supply of reserves. A more restricted and less flexible hydropower system will affect the costs for hydropower producers and can result in a higher and more variable reserve capacity prices.

V. CONCLUSION

This work has estimated the income distribution for hydropower plants participating in the spot market and the market for spinning reserve capacity under specific conditions. The study was done for selected weeks and for different cases for spinning reserve procurement for the Nordic region in a 2030 scenario with high shares of variable renewable energy sources. The analyzed snapshots show that for some plants the income from selling spinning reserve capacity can amount to up to 54 % of the total income in certain weeks, provided a "conservative" market design for reserve procurement. The results illustrate the importance of including several markets when analyzing future income potential of hydropower plants, such as in investments analyses.

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APPENDIX

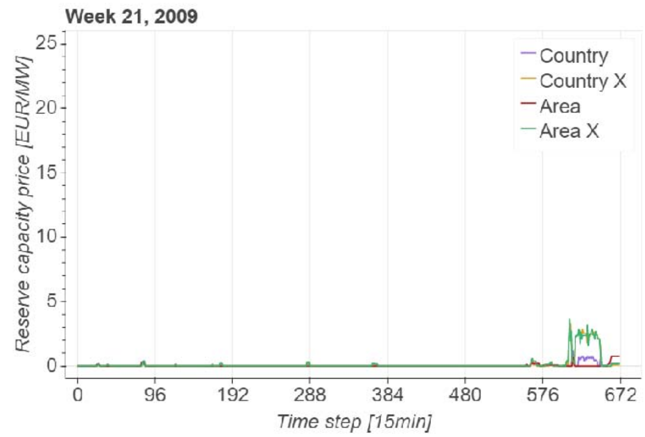

Fig. 5 Prices for upward reserve capacity (EUR/MW) in NO5 for week 21. The results show the Country, Country X, Area and Area X case.

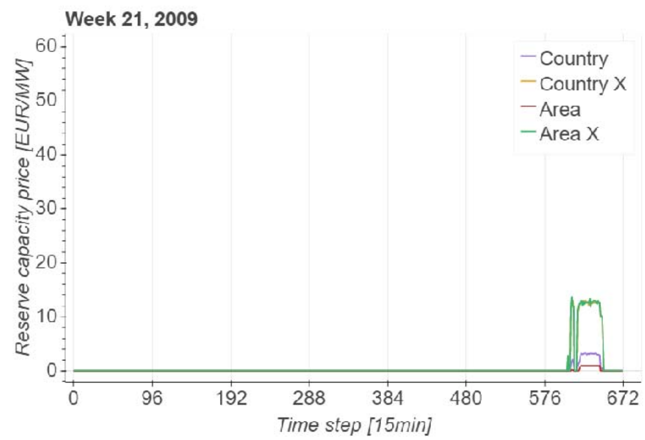

Fig. 6 Prices for downward reserve capacity (EUR/MW) in NO5 for week 21. The results show the Country, Country X, Area and Area X case.

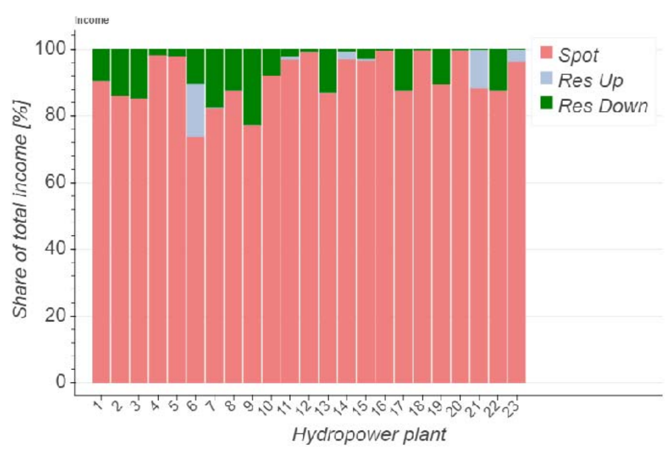

Fig. 7 The share of total income (%) from the different markets for hydropower plants delivering reserve capacity in NO1 for the Area case in week 21.

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