Available online at www.sciencedirect.com

ScienceDirect

Energy Procedia 87 (2016) 141 – 148

Energy Procedia

5th International Workshop on Hydro Scheduling in Competitive Electricity Markets

Profitability of a hydro power producer bidding in multiple power markets

Caroline Rasmussen[a], Jakob B. Ø. Hansen[a], Magnus Korpås[a,*], Marte Fodstad[b,**]

[a]Dept. of Electric Power Engineering, NTNU, Høgskoleringen 1, 7491 Trondheim, Norway
[b]SINTEF Energy Research, Sem Sælands vei 11, 7034 Trondheim, Norway

Abstract

The production scheduling of a hydro power producer exposed to the day-ahead, balancing and capacity market is examined to find what profit the producer may achieve by strategically bid in the above mentioned markets. Optimizing the bidding in multiple markets is expected to be increasingly important in the coming years as the share of renewable energy in the power system grows. A multi-stage, multi-scenario, short-term deterministic prototype model undertakes this task. The producer is assumed to be a price taker and is risk neutral. The results of the optimization have shown that a hydro power producer in the case-study area increases the expected income by participating in the balancing market. The results suggest that by utilizing the balancing market, the profit may increase by up to 5.86% per day, depending on the season. This is compared with the original income when bidding into the day-ahead market only. Furthermore, the simulations of future power prices have shown that profitability is expected to increase with price volatility. These findings underline the need to include balancing markets in production planning. The capacity market, RKOM, was also implemented. This market proved not to be profitable in this case study, but the conclusion might change if the future RKOM market price rise. Measures to reduce risk are also examined, creating valuable decision support to the producer.

Peer-review under responsibility of SINTEF Energi AS

Keywords: Power markets; day-ahead market; balancing market; capacity market; hydro power scheduling; intermittent energy

1. Introduction

Hydro power plays an important role in a power system focusing on mitigation and adaption to climate change. An important market driver is the European Union's (EU) ambitious climate and energy policy that has been dominant throughout the last decade, most importantly the 20-20-20 energy and climate targets [1]. Investments in wind and solar energy are expected to contribute considerably to achieve these goals [2]. These energy sources are heavily weather dependent causing intermittent generation. Consequently, challenges related to the power balance develop. Norwegian hydro power is flexible with the ability to mitigate the consequences from fluctuating renewable generation.

* Tel.: +47-970-42-009 ; e-mail: magnus.korpas@ntnu.no
** Tel.: +47-926-16-498 ; e-mail: marte.fodstad@sintef.no
E-mail address: postmottak@adm.ntnu.no

Peer-review under responsibility of SINTEF Energi AS
doi:10.1016/j.egypro.2015.12.344

Another aspect that drives the need for balancing services is the promotion of market efficiency within the Nordic power market. The EU has a goal of moving towards one common interconnected power system in order to deal with intermittency issues posed by renewable generation, enable diversity of suppliers and enable competition in the European market [3]. More cross-border transmission capacity enables the TSOs to cooperate with the power exchange companies to establish a common intra-day market. This gives the participants the opportunity to deal with the uncertainty related to power generation. The technological differences between the Nordic and European power system create dissimilarities in the cost of balancing services. Thus, trade of balancing services is likely to be more profitable in the future. The European energy trends create great business opportunities to Norwegian hydro power producers, as the energy source has low costs with high regulating abilities.

2. Model Description

The objective of this work has been to investigate the profitability a hydro power producer may achieve by participating in the day-ahead, balancing and regulating capacity market. These will be referred to as DA, BM and RKOM respectively. The DA, often denoted the spot marked, is the largest market and is closed at noon the day ahead of delivery. In BM tertiary reserve energy is traded, which is used to ensure balance between demand and supply within the hour of operation. In both markets the participants bid price and volume that will be activated based on price in merit-order.

The RKOM is a capacity market within the Norwegian balancing market that ensures adequate up-regulation resources by using options. Participants are paid to guarantee that they participate in the balancing market if required with power production or consumption disconnection. This market is cleared before the period of planning starts. The RKOM is split in two products. In RKOM-H bids are accepted for the entire day or the entire night. The RKOM-B offers more flexibility, at the cost of reduced price according to rules applied by the TSO (Statnett).

A prototype of a stochastic multi-stage, short-term model that undertakes this task has been developed by SINTEF Energy Research as a part of the research project 'Integrating Balancing Markets in Hydro Power Scheduling Methods'. The full model description is found in [4].

The model considers a power producer who bids into DA and BM. Based on scenarios of inflows and market prices, the model optimizes the utilization of a hydro power system in order to maximize the sum of the profit within the model horizon and the future value of the unused water. The physical flows and volumes are illustrated in Figure 1.

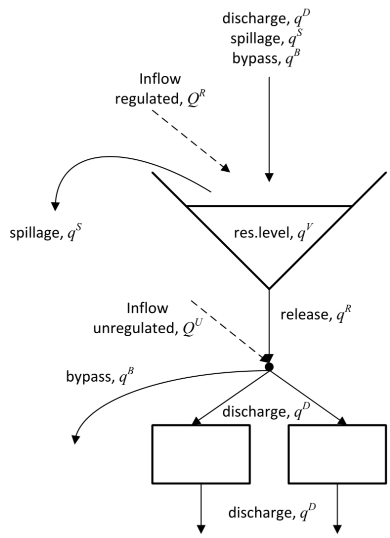

Fig. 1. A hydro power unit with a reservoir and two generators. Solid lines are flows (decision variables) and spotted lines are input parameters [5].

The model is solved in stages. First, bidding is done in DA. In the second stage, DA is cleared and bidding is done in BM. The BM is cleared in the final stage. This means that the BM prices are unknown at the time of bidding in the DA.

The bidding is done by using a set of 64 price points as input to the model. The prices are uniformly distributed between the lowest and highest price across all scenarios. The model then decides the optimal bid volume at each price point. The volume that will be produced in each scenario is then decided by linear interpolation between the price points.

The BM is modeled so that only bids corresponding to the direction of regulation will be accepted. Thus, up-regulation will only occur when the BM prices are higher than the DA prices and vice versa.

There are mainly two model assumptions one should be aware of. Firstly, the model assumes that the producer is a price taker. This means that the producer decisions do not affect the market price in any of the markets. The second assumption is that the producer is risk neutral. The producer will act based on expected revenues regardless of the risk involved. Thus, an alternative way to handle risk has been examined.

The profitability of bidding in BM was evaluated by comparing model runs with only DA bidding and bidding in both markets. To simulate possible increased intermittent generation in the future, the model was also run with increasing volatility of the spot- and balancing market prices.

In addition to the existing model functionality provided by SINTEF Energy Research, some modifications were added by the authors. RKOM was implemented in the model with only the reserved capacity as input. This capacity could not be traded in DA. The activated capacity in BM was then forced to be greater or equal to the reserved capacity whenever the BM prices were higher than the DA prices. The goal was to find the cost of reserving capacity and compare it with current market prices. For simplicity, only RKOM-H was modeled.

Separate simulations were done with different amounts of reserved capacity in RKOM. The results were compared with the results without any reserved capacity. The total losses of reserving capacity compared to not participating in RKOM could then be found and used to calculate the marginal price per unit of reserved capacity required to break even. Only data for the winter 2014/2015 was available and the RKOM implementation was therefore only run for week 1 and 44.

In order to handle risk, a method based on a safety-first strategy [6] was implemented. Minimum levels of profit, i.e. safety levels, were used as input parameters. These safety levels consist of results from simulations with BM deactivated, Obj_s^{DA}, and a subtracted tolerance factor, λ. The outcome of each scenario in consecutive simulations, obj_s, was then forced to be larger than the safety levels. This is mathematically formulated in Equation 1. The method for handling risk is intended to illustrate a concept; therefore, the risk handling was tested for week 14 only.

$$obj_s \geq Obj_s^{DA} - \lambda, \quad s \in \mathcal{S} \tag{1}$$

3. Case Study

The case study was based on the Tokke-Vinje hydro power system in Southern Norway. It consists of 11 reservoirs and 8 power plants that are interconnected as shown in Figure 2. The total installed capacity is 990.4 MW. The model has been run for four different weeks: 1, 14, 27 and 44.

The data used has been gathered from different data sets supplied by SINTEF Energy Research and modified to fit the model format. This includes a data set describing inflow, start up costs and generator capacities. The price inputs were based on historical prices. An overview of the simulated market scenarios is presented below in Table 1, continued by an explanation of the necessary modifications. NO2 refers to the southernmost of the five bidding areas in Norway.

In order to have price input with high validity in the optimization model, price scenarios were generated based on historical price observations [4] from the Nord Pool Spot FTP-server [7]. For each week, the model was run once with BM deactivated, so that only day-ahead trading is allowed, referred to as DA Only. In addition, the model was run three times with different input prices in BM. These cases are referred to as Normal BM, Vol1 and Vol2, see Table 2. The Normal BM case contains BM prices based on data without modifications. Vol1 and Vol2 were created to simulate the expected increase in price volatility as a consequence of a future increase in intermittent generation. The adjustments in the BM scenarios are explained in the following paragraphs.

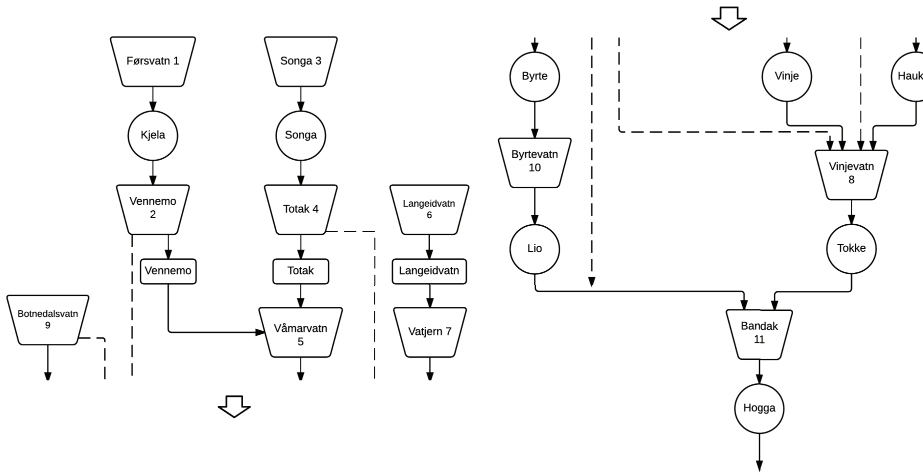

Fig. 2. A flow chart showing all reservoirs and hydro power stations in the Tokke-Vinje hydro power system. Arrows indicate flow direction. The trapezoids are reservoirs, circles are hydro power plants and squares are gates. The dotted lines represent the water way for bypass and spillage that does not follow the same path as the discharge.

Table 1. Simulated market scenarios

Market case	Description
DA Only	No trade in the BM
Normal BM	Trade in the BM activated, BM prices based on historical data from NO2 without modifications
Vol1	Probability of BM prices adjusted
Vol2	Price difference and probability of BM prices adjusted
RKOMX	BM prices as in the Normal BM, RKOM activated with X MW/h reserved capacity

Price Volatility 1 (Vol1). The price differences are identical as in the Normal BM case, while the probabilities were changed. The probability of no regulation, i.e. scenario 4, was halved as it is more likely that regulation is needed. The reduction in probability of scenario 4 was distributed across scenarios 2, 3, 5 and 6 so that the probability of these scenarios were increased with an equal amount relative to the probability of the respective scenarios. The probability of the extreme scenarios 1 and 7 were kept constant. This is because these scenarios likely are due to rare events such as outages and will likely not become more frequent.

Price Volatility 2 (Vol2). The probability distribution is the same as for Vol1, but with higher price differences in scenario 3 and 5. The price difference in these scenarios was doubled. This is to simulate an increased demand for regulation in the scenarios with high probability.

The marginal water value cuts were calculated in ProdRisk [8] in order to create consistency between short- and long-term optimization. ProdRisk is a stochastic dual dynamic programming developed by SINTEF. Several water value cuts are calculated around a reference price and reservoir levels. The reference price and reservoir levels were calculated based on historical prices [7] and the operating license conditions for Tokke-Vinje [9].

Table 2. Range of price differences between DA and BM with corresponding probabilities, week 1.

	Normal BM		Vol1		Vol2	
BM scenario	Price difference [EUR/MWh]	Probability [%]	Price difference [EUR/MWh]	Probability [%]	Price difference [EUR/MWh]	Probability [%]
1	-75.17	0.26	-75.17	0.26	-75.17	0.26
2	-19.74	2.84	-19.74	3.10	-19.74	3.10
3	-5.69	52.46	-5.69	57.26	-11.39	57.26
4	0.00	15.30	0.00	7.65	0.00	7.65
5	4.40	26.84	4.40	29.29	8.81	29.29
6	22.31	1.55	22.31	1.69	22.31	1.69
7	111.07	0.75	111.07	0.75	111.07	0.75

4. Results and discussion

The simulations have shown that a hydro power producer increases the expected income by participating in the balancing market. The key findings are summarized in Table 3 and 4.

Table 3. Value of objective and contributing factors with BM disabled [$\frac{\text{kEUR}}{\text{day}}$].

	Week 1	Week 14	Week 27	Week 44
Spillage cost	0.00	0.00	0.00	0.00
Start up cost	0.70	0.70	1.10	0.40
Day-ahead income	900.76	838.08	669.38	728.73
Increased water value	-504.13	-491.49	526.44	-343.40
Objective	395.13	344.79	1193.72	383.72

Table 4. Value of objective and contributing factors with BM included. Price input according to the Normal BM case [$\frac{\text{kEUR}}{\text{day}}$].

	Week 1	Week 14	Week 27	Week 44
Spillage cost	0.00	0.00	0.00	0.00
Start up cost	1.16	0.53	1.46	1.02
Day-ahead income	1001.99	935.78	695.43	728.73
Balancing market income	-102.70	-72.47	-18.84	6.88
Increased water value	-481.35	-496.54	526.98	-340.52
Objective	415.85	365.01	1201.46	392.72
Gain from including BM	20.72	20.22	7.74	9.00
as % of original income[1]	5.24%	5.86%	0.65%	2.35%

This finding is as expected with the following reasoning. Suppose the DA allocation from the simulation without the BM should be kept with no changes. It is clear that allowing trade in the BM afterwards would provide at least the same solution. Most likely the solution will be improved, as some prices in the BM should provide beneficial trade options. In addition, letting the model choose the optimal allocation in the DA based on the expected BM price will provide an equal or better solution. Similar results have been proved analytically by [10].

The results did also provide information about how the gains were achieved. When the total income from the DA increases by including BM, the BM income was negative. This is the case in week 1, 14 and 27. This indicates that the gains were achieved by bidding more into the DA and then down-regulate in the BM. This reasoning is supported by Figure 3, which show the average hourly volumes traded in the DA Only and the Normal BM case.

[1] The percentages show an increase in income from including BM compared with the original income when bidding in DA only.

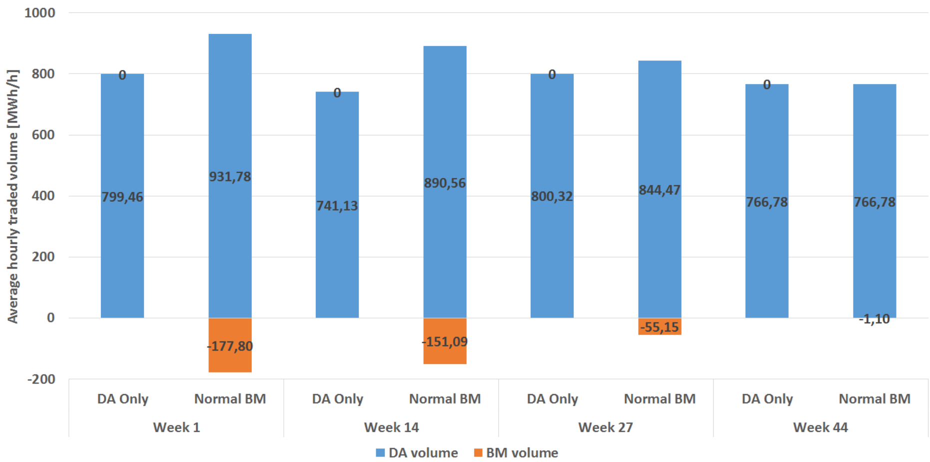

Fig. 3. Average hourly volumes traded in the DA and BM for all weeks [$\frac{\text{MWh}}{\text{h}}$].

For week 44, the DA income was unchanged and the BM income was positive. With the above reasoning, this indicates that up-regulation is dominant. However, the results covering the traded volumes showed the opposite. Hence, there was more volume traded as down-regulation, but the prices made the total income larger from up-regulation. This explains the positive BM income in week 44.

The results indicate changes in the overall production level when BM is included. The increase in value of the unused water was smaller in week 14 when including the BM compared to DA Only. This reveals that the overall production level was increased. The opposite is the case for week 1, 27 and 44.

When different levels of price volatility between DA and BM were introduced in the model, the simulations showed that the expected profitability was increased with price volatility. Table 5 presents this result.

Table 5. Value of objective and contributing factors with different levels of price volatiliy. Price input according to the Vol1 and Vol2 cases [$\frac{\text{kEUR}}{\text{day}}$].

	Week 1		Week 14		Week 27		Week 44	
	Vol1	Vol2	Vol1	Vol2	Vol1	Vol2	Vol1	Vol2
Day-ahead income	1014.13	1027.97	951.13	951.13	731.85	734.07	728.94	787.72
Balancing market income	-121.06	-164.72	-87.9	-80.52	-50.99	-83.02	7.31	-80.43
Increased water value	-472.44	-408.02	-494.02	-476.46	524.52	576.29	-340.36	-298.35
Objective	418.51	452.75	367.46	392.28	1203.53	1224.91	393.44	406.25

Furthermore, the results showed that the profitability in both markets was affected. The DA income was increased or remained unchanged with price volatility in all the seasons. Since down-regulation was dominant in all the four weeks with normal prices, it is to be expected that the model will down-regulate even more as the volatility increase. Bidding more into DA opens up for more down-regulation in BM.

The BM income was most affected by the changes, with the income expected to decrease with the volatility in most of the cases. In week 27, for instance, the expected balancing income was decreased with 107.1% and 340.7% for Vol1 and Vol2, respectively. The decrease in BM income corresponds well with the above-reasoning that the model aims to down-regulate more as volatility increases.

With the RKOM restrictions included in the model, the objective value was reduced by up to -10.91 kEUR per day, as shown in Table 6. The tables also show that the DA income is reduced, while the BM income is increased with larger RKOM capacity. This is as expected, as the restrictions force the producer to hold back in DA and sell up-regulation when needed. The up-regulation volume in BM was also larger or equal to the reserved capacity for all scenarios with higher BM than DA price. This indicates that the implementation works as intended.

Table 6. Change in results when introducing RKOM compared to the Normal BM case for week 1.

	Week 1			Week 44		
Capacity reserved in RKOM [MW/h]	20	50	80	20	50	80
Day-ahead income [kEUR]	-19.54	-41.55	-69.37	-9.94	-34.04	-48.25
Balancing market income [kEUR]	8.66	21.18	36.52	6.10	21.50	28.55
Increased water value [kEUR]	8.19	13.56	21.90	3.23	10.60	16.12
Objective [kEUR]	-2.68	-6.78	-10.91	-0.60	-2.13	-3.84

The goal of this implementation was to estimate a price per MW/h that the producer would need to get payed in order to break even compared to not trading in the RKOM. This was done similarly to the Secondary Reserve Cost Curve computed in [11] by using Equation 2.

$$P^{RKOM} = \frac{\Delta Obj * 1000}{X^{RKOM} * 19} \tag{2}$$

ΔObj is the reduction in objective function in kEUR compared to the Normal BM case. X^{RKOM} is the reserved RKOM capacity, measured in MW/h in each of the 19 daytime hours. The resulting price per MW/h, P^{RKOM}, is listed in Table 7.

Table 7. RKOM price required to break even for different reserved RKOM capacities.

	P^{RKOM} [EUR/MW/h]	
RKOM volume [MW/h]	Week 1	Week 44
20	7.05	1.58
50	7.14	2.24
80	7.18	2.53

RKOM is a new market, thus the only existing market data available is from the winter 2014/2015. This data can be found in Table 8. The data shows that the traded capacity in RKOM was highest in the weeks 3 through 10. The price peaked in week 6. Except from a very small margin at 20 MWh/h in week 5, this was the only price level that would make it beneficial for the producer to participate with the results from the simulated week 1. The P^{RKOM} from week 44 is lower, but it would not be beneficial to trade before the price reaches the level of week 3, which indicates that there were no need for capacity services before this time.

Table 8. RKOM-H-day market data for 2014/2015 from [12]. Prices displayed are per MW/h. A conversion factor of 8.5 NOK/EUR was used. There were either no trade or no data available for weeks not displayed. There were no trade at night in the RKOM during this period.

		RKOM-H day		
Year	Week	Volume [MW]	Price [NOK]	Price [EUR]
2014	50	30	4.5	0.529
2014	51	0	0	0
2015	2	90	5	0.588
2015	3	290	15	1.765
2015	4	410	50	5.882
2015	5	415	60	7.059
2015	6	382	90	10.588
2015	7	395	40	4.706
2015	8	430	40	4.706
2015	9	420	40	4.706
2015	10	105	5	0.588
2015	19	70	9.98	1.174
2015	21	220	9.9	1.165

The producer takes a risk by participating that was not accounted for in the above calculations because RKOM is cleared for an entire week at a time. This risk will be weighted against the expected increase in revenues. The results show that the conditions for which the revenues are increased were rare during the winter season 2014/2015. Therefore, RKOM did not at the time seem very attractive for this particular producer.

When the safety-first strategy was introduced to reduce risk, the outcome of all scenarios with losses compared to the DA only case were significantly improved. In week 14, the results changed from a 21.50% chance of ending up in a scenario with losses around 20000 EUR to a 8.7% chance of a loss of 1000 EUR. This was at the cost of a 2300 EUR reduction in expected income. This is valuable decision support for a producer.

5. Conclusion

The results of the optimization have shown that a hydro power producer in the case-study area increases the expected income by participating in the balancing market. Furthermore, the results of the optimizations showed that the profitability is expected to increase further with price volatility. This is highly relevant as the market prices are likely to become more volatile due to the expected increased penetration of intermittent energy like wind- and solar power. These findings underline the need to include balancing markets in production planning, which creates a major business-opportunity for Norwegian hydro power producers.

The results from the simulations with RKOM included indicate that it is not presently profitable to participate in the capacity market. However, the changes in bidding strategy that were necessary when RKOM was included were similar to the changes that were done to reduce risk. This may make a producer willing to participate even though the expected profits are reduced. Furthermore, it may be attractive to participate in RKOM in the future if the prices of capacity reservation increase sufficiently.

Acknowledgements

The presented work is part of the research project “Integrating Balancing Markets in Hydropower Scheduling Methods” funded by the Norwegian Research Council and industry partners. This paper is a summary of a Master’s thesis [4] that is published on http://ntnu.diva-portal.org. Please refer to this thesis for a detailed model description and results.

References

[1] European Commission, “The 2020 climate and energy package,” 2014. http://ec.europa.eu/clima/policies/package/index_en.htm.
[2] Statnett, *Systemdrifts- og markedsutviklingsplan 2014-2020.* Statnett, 2014.
[3] International Energy Agency, *Energy Policies of IEA Countries, 2014 Review*, 2014.
[4] J. B. Hansen and C. Rasmussen, “Profitability of a hydro power producer bidding in multiple markets,” 2015. Master’s thesis written at the Norwegian University of Science and Technology. https://daim.idi.ntnu.no/masteroppgaver/013/13596/masteroppgave.pdf.
[5] SINTEF Energy Research, “Balancing markets and their impact on hydro power scheduling,” 2014. The report is confidential.
[6] E. Gómez-Villalva and A. Ramos, “Risk management and stochastic optimization for industrial consumers,” 2004. http://www.iit.upcomillas.es/publicaciones/mostrar_publicacion_working_paper.php.en?id=130.
[7] NordPool FTP-server, 2015. ftp.nordpoolspot.com.
[8] A. Gjelsvik, B. Mo and A. Haugstad, *Long- and Medium-term Operations Planning and Stochastic Modelling in Hydro-dominated Power Systems Based on Stochastic Dual Dynamic Programming*. Springer Berlin Heidelberg, 2010.
[9] Statkraft, “Revisjonsdokument for tokke-vinjereguleringen 2013 med vedlegg,” 2013.
[10] T. Boomsma, N. Juul and S. Fleten, “Bidding in sequential electricity markets: The nordic case,” *European Journal of Operational Research*, 2014.
[11] F. Campos, A. Munoz San Roque, E. Sanchez-Ubeda, J. Portela, R. Gonzalez Hombrados, J. Rodriguez Marcos, and A. Gonzalez Castrillon, “Optimization of the bidding curve in reserve markets,” in *European Energy Market (EEM), 2013 10th International Conference on the*, pp. 1–6, May 2013.
[12] Statnett, 2015. www.statnett.no/Drift-og-marked/Markedsinformasjon/RKOM1/RKOM-uke/, Data collected from website 19.05.2015.