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RENEWABLES IN ELECTRICITY MARKETS

Building a day-ahead electricity market

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1 Introduction

To understand how electricity trading occurs, and how renewable energy is being integrated into the electricity market, it is crucial to understand how the concept of market clearing and power scheduling works in the day ahead market. The aim of this project is to understand and model a day ahead electricity market, using real data as inputs. A set-up of the day ahead market will be made using real data from Denmark from 2019 and 2020. The market clearing will be formulated as a linear program and solved using the Julia software, and market outcomes such as scheduled power producers, revenues and market prices will be analysed for the two regions DK1 and DK2.

2 Methodology

2.1 Formulating the Market Clearing

The market clearing mechanism is formulated as a linear program containing an objective function and constraints. All the parameters in the objective function and the constraints are in compact form, i.e. using matrices and vectors.

Note that supplier id. EW_1 will not participate in the market due to the feed-in tariff support, since the support scheme guarantee a fixed income independent of production.

2.1.1 Mathematical model

Variables. The variables introduced in the model are explained below.

- The vector y_{DK1} contains all the variables evaluating the scheduled generations in DK1 at each time unit - which have to be positive - and the demand in DK1.

$$y_{DK1} \geq 0 \tag{1}$$

- As above, the power generated by each market participant in DK2 and the total demand in DK2 is evaluated in y_{DK2}:

$$y_{DK2} \geq 0 \tag{2}$$

- Transmission limit. The transmission line between DK1 and DK2 can be used for maximum 600 MWh in either way. Therefore, the variable b_{eq} represents how much of the transmission line is used and is constrained as follows:

$$-600 \leq b_{eq} \leq 600 \tag{3}$$

Objective function. The objective function expressed in **Formula 4** aims at minimizing the total generation cost for DK1 and DK2, and therefore maximizing the welfare. c^T is a vector containing the bid price (transposed) of each supplier. In this model, the cost associated to the demand is set to zero since there's only one demand amount to be satisfied, i.e. there are no demand bids.

$$\min \ c_{DK1}^T \cdot y_{DK1} + c_{DK2}^T \cdot y_{DK2} \tag{4}$$

Constraints. The above objective function is subject to the following constraints:

- **Maximum Capacity.** The production from each generator has to be less or equal than the maximum available capacity for that given unit. b is a vector including all the available capacities and A is an identity matrix. The last value of b represents the demand and it is updated each hour considering imports and exports minus the generation from EastWind (for the case of DK2), since it has a feed-in tariff and it is therefore out of the market.

$$A_{DK1} \cdot y_{DK1} \leq b_{DK1} \tag{5}$$

$$A_{DK2} \cdot y_{DK2} \leq b_{DK2} \tag{6}$$

- **Balancing.** The balance in the two regions is evaluated at each time unit considering the maximum capacity of the transmission line:

$$A_{eq(DK1)} \cdot y_{DK1} = b_{eq} \tag{7}$$

$$A_{eq(DK2)} \cdot y_{DK2} = -b_{eq} \tag{8}$$

where $\mathbf{A}_{eq} = \begin{bmatrix} 1 & \dots & 1 & \dots & -1 \end{bmatrix}$ (-1 for the demand at the last item of the vector).

- **Load Shedding.** In order to consider the possibility of the load to be shed, the following constraints are built according to the different scenarios and complementing the non-negativity constraint of the last item in the variable vector, i.e. the demand. In the situation of the sum of maximum generation being more or equal than the demand in the two regions, the system is stable and balanced. Therefore, the variable representing the demand has to be greater or equal than the required demand. Taking into account the maximum capacity constraint for demand, this state enforces the demand variable to be equal to the initial total demand.

$$\text{if} \sum_{n=1}^{N-1} b_{j,n} \geq b_{j,N}, \quad y_{j,N} \geq b_{j,N} \qquad \text{(stable state)} \tag{9}$$

where
j: DK1, DK2;
N: number of variables in the b and y vectors
$y_{j,N}$: last value in the y vector for the two zones, therefore the demand.

On the other hand, if demand is higher than the maximum production possible in one of the regions, there is a shortage. Therefore, if the demand at a certain hour is greater than the maximum production of each region, then load has to be shed. The demand variable is set to be greater or equal than the sum of the maximum possible power production of each generator. Taking into account the maximum capacity constraint for demand, this state enforces the demand variable to fluctuate between the available power production in the region and the initial total demand.

$$\text{if} \sum_{n=1}^{N-1} b_{j,n} \leq b_{j,N}, \quad y_{j,N} \geq \sum_{n=1}^{N-1} b_{j,n}, \qquad \text{(load shedding)} \tag{10}$$

2.1.2 Revenues

After the market is cleared, the revenue for each and every market participant is calculated by formula 11. The revenues are calculated by multiplying the amount of power delivered y_i for supplier i with the market clearing price λ^S, since the system is based on a uniform pricing. If there's congestion there will be one price per region, according to the balancing equality constraints. For the wind producers, the support scheme comes on top of the market price in the case of a premium, and for the feed-in-tariff the price is set at a constant of the support amount, which is 20 €.

$$\lambda^S \cdot y_j \tag{11}$$

3 Results and Discussion

The script needed to replicate the results is uploaded together with this report, also all results for each time step are given as a supplementary Excel file, if needed. Note that converted xls to CSV files were used in the code, instead of the raw xls files from NordPool.

3.1 Market Clearing for two Market Time Units

The two time units analyzed are the hour 9-10 of 14$^{\text{th}}$ November 2019 (time unit 321) as example for a congested line, while the hour 6-7 of 2$^{\text{nd}}$ January 2020 (time unit 1049) is chosen to represent a situation in which the transmission line is not congested. The data obtained for those hours is summarized in **Table 1** below. In the congested line example, the market price for DK1 is more than four times higher than for DK2, and the total system cost is also significantly higher in the case of congestion compared to the case where there is no congestion. The reason for the much higher price in DK1 in the congestion case, is because the demand is higher than the power available from cheap suppliers in the DK1 area, especially because of low wind power production from WW1. Therefore the price in DK1 will be driven up by the need to cover demand using more expensive resources to cover demand. This shows the importance of increase transmission capacity, to minimize the market price in both zones and thereby maximize social welfare.

Table 1: Costs, demand and market price for the chosen time units

Time unit	**Total cost [€]**	**Demand & I/E [MWh]**	**Market price [€/MWh]**	**Demand & I/E [MWh]**	**Market price [€/MWh]**
		DK1		**DK2**	
321	108698.8	3074	80	1925.3	17
1049	4148.4	2926	17	1858.4	17

It is important to underline that the demand value is already considering the import/export required at that particular time for each zone and the wind power generated by EW_1. In fact, since it is supported with a feed-in tariff of 20 €/MWh, it will not enter the market and therefore it is not considered in the merit order curve but it will simply dispatch its power whenever its available.
On the other hand, since WW_2 and EW_2 are receiving a premium tariff as support, the best way for them to be dispatched in the market is to offer at the opposite of how much the support is. [1] Therefore, their market bids are respectively -17 and -12 €/MWh.

3.1.1 Congested line time unit

In this situation, the demand can't be satisfied only by the wind production in the two separate areas, therefore the transmission line is needed as much as possible to compensate the amount required in order to keep the prices low. During a congested line-time unit, in fact, the power is flowing from the low price (DK2) to the high price area (DK1). The scheduled producers are summarized in **Table 2**.

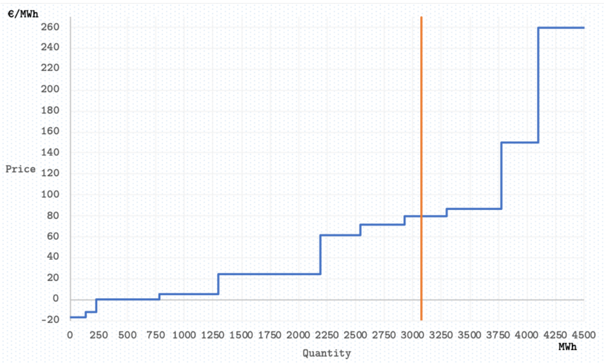
Table 2: Power generation and revenues for a congested line - Time unit 321 (14/11/2019, 9-10)

Supplier	Generation [MWh]	Revenues [€]
G_1	380	30400
G_2	350	28000
G_3	0	0
G_4	150	12000
G_5	0	0
G_6	900	72000
G_7	0	0
WW_1	555.2	44416
WW_2	138.8	13463.6

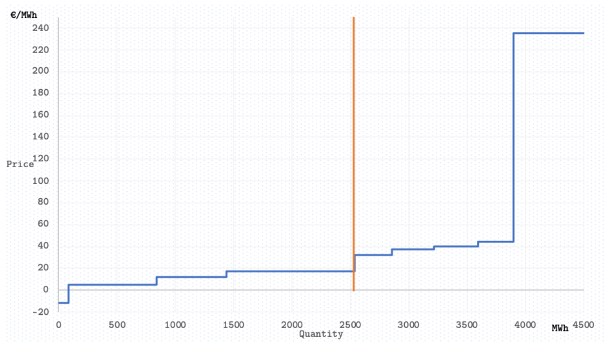
Supplier	Generation [MWh]	Revenues [€]
G_8	1088	18496
G_9	0	0
G_{10}	0	0
G_{11}	0	0
G_{12}	0	0
G_{13}	750	12750
G_{14}	600	10200
G_{15}	0	0
EW_1	9.7	194
EW_2	87.3	2531.7

During time unit 321, for a congested line, the price in DK2 is much lower, as the region is able to cover demand without using the most expensive generators, therefore it is able to send 600 MWh towards DK1 from its cheapest producers (87.3 MWh from EW_2 at -12 €/MWh and 512.7 MWh from G_{13} at 5 €/MWh). The price settled in DK1 is then 80 €/MWh while in DK2 is 17 €/MWh.
The two merit order curves are obtained adding 600 MWh of power in the DK1 according to the respective offers and adding 600 MWh of demand required in the DK2 slope, and they are shown in **Figure 1**.

[1] P. Pinson. *2.5 Impact of Regulation and Support Schemes*. Electricity Spot Markets. Technical University of Denmark. 2020.



(a) DK1



(b) DK2

Figure 1: Merit order curve for the two zones - congested line

3.1.2 Non-congested line time unit

During the time unit 1049, the demand is quite high but, in spite of the previous case, the wind production is high, therefore it is able to supply all the demand required in the two separate zones maintaining a low market price. In the case of no congestion, only the wind producers are scheduled in DK1, while the three cheapest generators (G_8, G_{13}, G_{14}) are scheduled in DK2, as shown in **Table 3**. These are also the cheapest non-wind generators for both regions, and therefore in a non-congestion case these will be scheduled in addition to wind.

Table 3: Power generation and revenues for a non congested line - Time unit 1049 (02/01/2020, 6-7)

Supplier	Generation [MWh]	Revenues [€]
G_1	0	0
G_2	0	0
G_3	0	0
G_4	0	0
G_5	0	0
G_6	0	0
G_7	0	0
WW_1	2089.6	167168
WW_2	522.4	50672.8

Supplier	Generation [MWh]	Revenues [€]
G_8	412	7004
G_9	0	0
G_{10}	0	0
G_{11}	0	0
G_{12}	0	0
G_{13}	750	12750
G_{14}	600	10200
G_{15}	0	0
EW_1	45.6	912
EW_2	410.4	11901.6

In this case, since there is no congestion, the market is cleared considering the zones together in a unique merit order curve, shown in **Figure 2**.

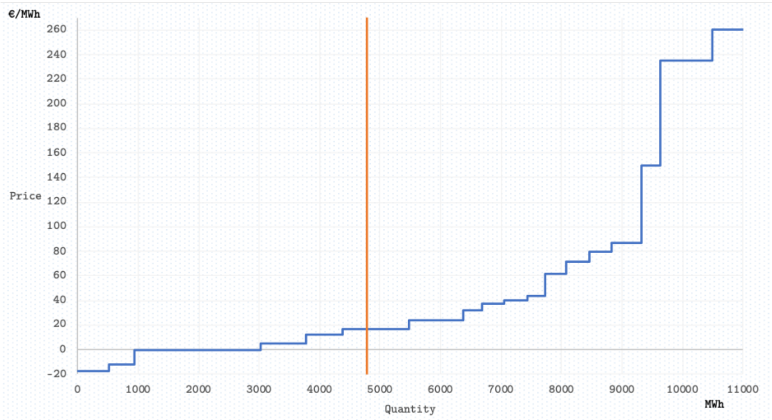


Figure 2: Merit order curve - no line congestion

3.2 Revenues

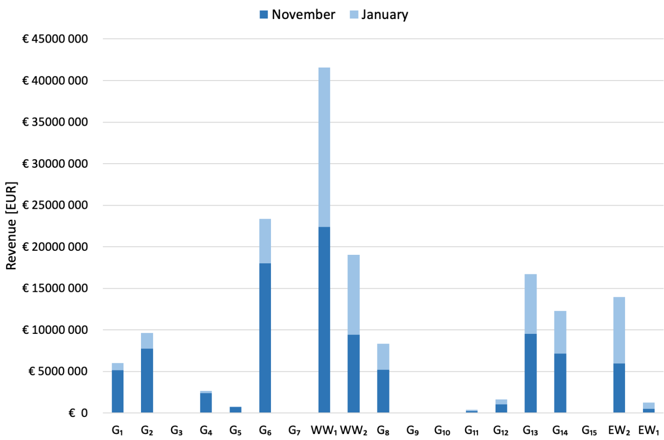
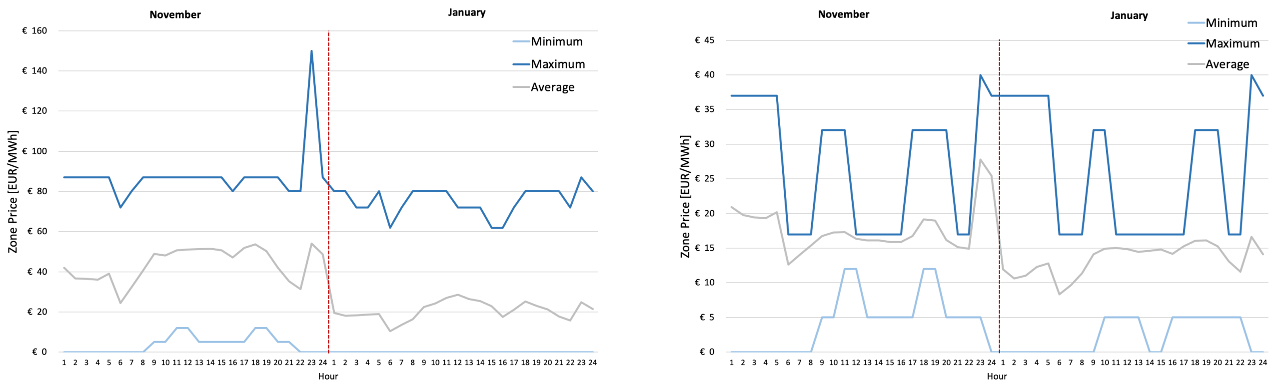


Figure 3: Revenues for all generators for January and November, and in total.

In **Figure 3** the total revenue for the generators are summarized. As already mentioned, EW_1 gets a fixed income of 20 €/MWh delivered, no matter what the market price is. Compared to the other wind producers, EW_1 has the least revenue. This is due to the support scheme, where 20 € is less than the average system price most of the time in the period studied. Both WW_2 and EW_2 gets an additional support on top of the market price, which gives a price which is always higher than what WW_1 receives, and most of the time higher than what EW_1 receive. Although, WW_1, which is the only wind producer without any support scheme, is the wind producer with the highest revenue of all the wind producers, and in fact of all the producers in the market. This is due to the high share of production (80%) in its region. This shows that, once a wind producer is fully established, might not have any need of support schemes to become competitive in the market. In the meantime, however, support appears necessary for the newly installed producers in order to abate costs and to reach grid parity.

It can also be seen from the revenues that, as to be expected, the lower the price the higher the revenue is for the generators, as the low price units will be scheduled more often. In fact, G_7, G_9 and G_{15} does not generate any revenue at all in the period. For G_7 and G_{15} this can be explained by the high offering price (see Appendix) for those generators, which is probably due to the fact that they are coal generators. This leads to them being pushed out of the market, being always to the right of the equilibrium point and therefore not being scheduled, and thus no revenue is gained. G_9, on the other hand have a much lower price, but it is not generating any revenue either. This shows how sensitive the market can be, as the bidding price is just 4 € higher than G_{10} but it is enough to be out of the market at all times. G_6 and G_8 are only operating at certain times, but due to the low price they get high revenues. The total revenues for DK1 is approximately 260% higher than the total revenues in DK2.[2]

3.3 Market Outcome Analysis - November 2019 & January 2020

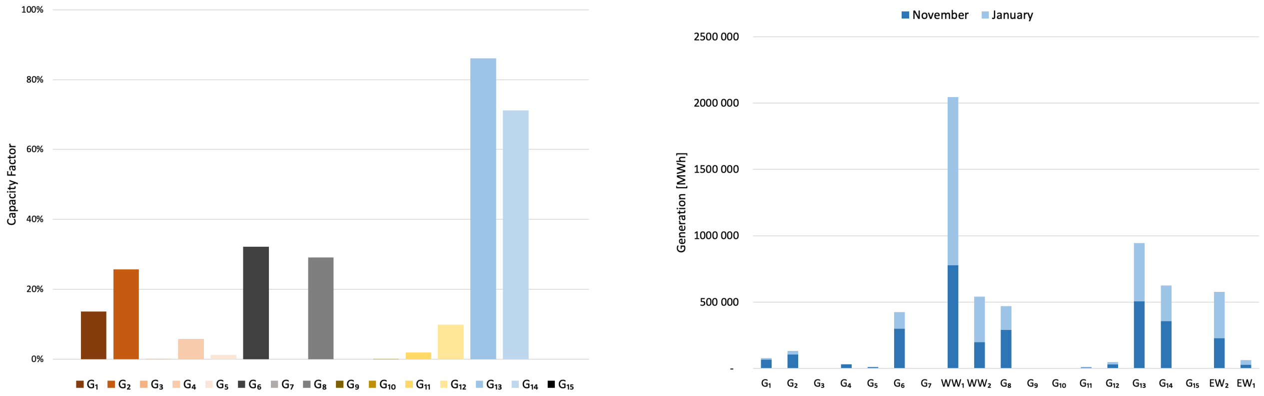


(a) DK1 (b) DK2

Figure 4: Prices in the two regions

Figure 4 shows the maximum, minimum and average hourly prices for November and January for DK1 (a) and DK2 (b). The average price is approximately twice as high in DK1 compared to DK2 in November. The average price is also higher in DK1 for January. For both regions the prices are both lower and more stable in January. The greater capacity of the wind production in DK1 results in having more minimum prices at 0, compared to DK2; however, this also results in higher peak prices when there is no wind, since DK2 is able to compensate that absence with cheap solutions such as hydro and nuclear power. DK1 non-wind generators have generally higher costs than DK2. Therefore, the average market price in DK2 is generally lower than the market price in DK1.

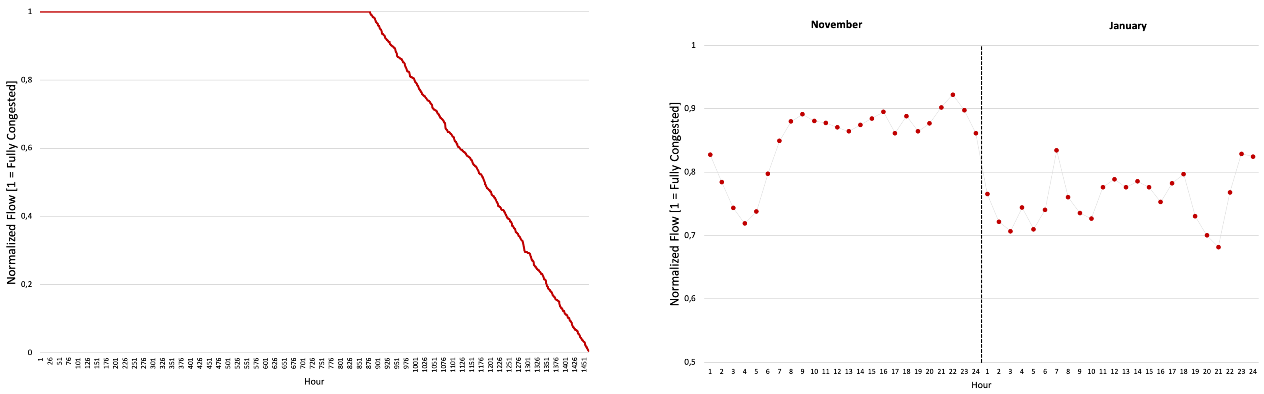
[2]See sheet "revenues" on the attached Excel file for detailed calculations.



(a) Capacity factor (b) Generation

Figure 5: Capacity factor and generation

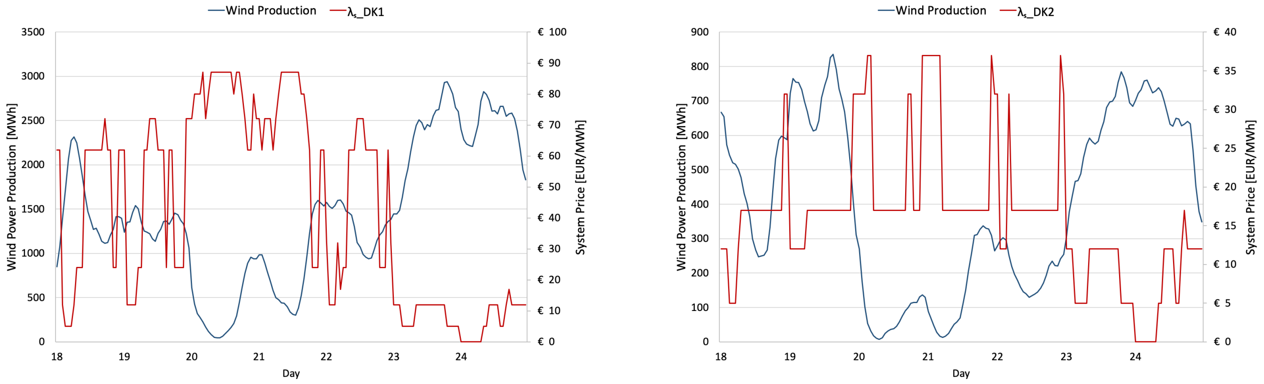
Figure 5 shows the capacity factor (a) (except wind) and the total generation (b) for each generator. G_{13} and G_{14} are the two non-wind generators (hydro and nuclear power plants) that have the most generation and highest capacity factor, due to the fact they are the two with the lowest price. WW_1 is the generator with, by far, the most generation. Especially for January the production is high, which explains lower prices in January. Generally the conventional generators produce more in November than in January which also drives the price up for November. EW_2 is the only wind producer with very low generation. Note that G_6, even though it has the highest revenue behind WW_1, generates similar amounts compared to many of the other generators. This is because of the much higher system price in DK1 where G_6 is located. In fact, for example, G_{13} and G_{14} are generating more power but still they have less revenue due to the different system prices in the two regions.



(a) Congestion duration curve (b) Hourly congestion

Figure 6: Congestion duration curve (a) and hourly congestion (b)

Figure 6 shows the normalized flow (a) and the hourly congestion for November and January (b). It can be seen that around half of the time there is full congestion. There is more congestion in November than in January, which will differentiate the prices more in November compared to January. There is generally a quite high power flow between the two regions, around 70-80% of transmission capacity for January and 80-90% for November.



(a) System price vs. wind production for DK1

(b) System price vs. wind production for DK2

Figure 7: Wind production vs. System price in DK1 (a) and DK2 (b) for November 18-24, 2019

Figure 7 is showing how the system price changes according to the wind production in the two regions. It can clearly be seen how the two variables are connected, as the system price is low when there is a lot of wind production and vice versa. This also leads to quite unstable system price in periods with varying wind production, as can clearly be seen in the two first days in figure 7 (a).

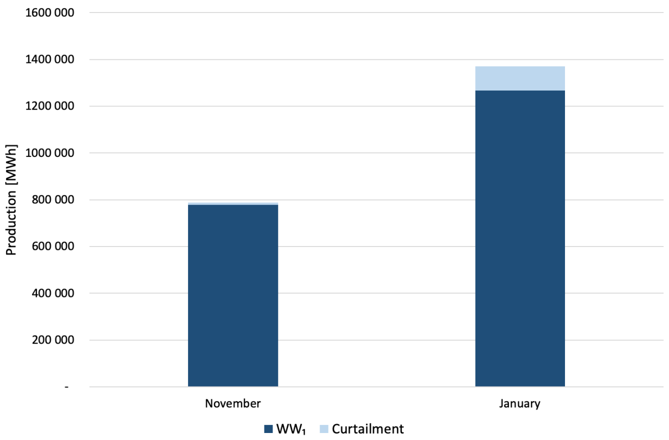


Figure 8: Curtailment for WW_1 in MWh for November and January

Figure 8 shows the wind curtailment for WW_1, which is the major wind producer in DK1, in November and January. There's no wind curtailment in either month for DK2 and no curtailment for WW_2 in DK1. In November there is little curtailment at 8 GWh, while in January the amount is 103 GWh; totalling an amount

of 112.194 GWh of curtailed wind power in DK1. The curtailment happens in 187 hours, where the minimum curtailed quantity is 2 MWh and the maximum curtailed quantity is 1693 MWh. This happens because of wind overproduction, compared to the demand required in DK2, and because the transmission line is congested between the two areas. So, even if DK2 was "in need" of importing cheap wind power from DK1, it was unable to do it since the line was congested and the extra wind power production was curtailed. In fact, during January, the wind production is generally quite high, therefore not always needed.
Finally, there were no negative prices or load shedding in the analyzed period. The negative prices didn't appear because the wind suppliers with a premium were not able to satisfy the total demand of either DK1 or DK2 at any time period. While for load shedding, there were no time periods when the load was greater than the available power production (plus potential line imports).

4 Conclusion

In this report, a day ahead electricity market model has been created based on real data from Denmark. A linear program has been developed to simulate market outcomes for November 2019 and January 2020. The results show that the prices are higher for DK1, and therefore the revenues is also higher for that region. Prices are higher in November compared to January, mainly due to hours with no wind and congestion, thus the need for using more expensive power suppliers pushed up the prices. The amount of wind production clearly impact the system price, as higher production means lower price and vice versa.

Renewable power changes the market, by pushing the prices down and thereby pushing expensive units such as coal units out of the market. This is both positive and negative. More renewable power will be produced which gives an lower environmental impact and cheaper price. Although, conventional plants such as coal plants could face decommission, and thereby the system will loose valuable base generators in case of lacking renewable power due to fluctuating weather conditions. Therefore an optimal mix is needed to provide a stable system with less chance of power outage and as low price as possible. A possible solution could be to upgrade base generators to be cleaner by, for example, repowering them to use cleaner fuel, in order to have safe conventional peak generators available.

Appendix

Import/Export values:

- DK1 imports 100 MW from Norway continuously
- DK1 exports 120 MW to Germany, every day between 8am and 3pm, and 0 for the rest of the time
- DK2 imports 80 MW from Sweden, every day between 11am and 5pm, and 0 for the rest of the time

Table 4: Suppliers info. Nuke22 is the only supplier that does not offer for all time units.

Supplier name	**Supplier id.**	**Area**	**Quantity [MWh]**	**Price [€/MWh]**	**Offering strategy**
FlexiGas	G_1	DK1	380	72	Operates/offers for all time units
FlexiGas	G_2	DK1	350	62	Operates/offers for all time units
FlexiGas	G_3	DK1	320	150	Operates/offers for all time units
Peako	G_4	DK1	370	80	Operates/offers for all time units
Peako	G_5	DK1	480	87	Operates/offers for all time units
Nuke22	G_6	DK1	900	24	Only operates/offers for time units between 5am and 10pm
CoalAtLast	G_7	DK1	1200	260	Operates/offers for all time units
Nuke22	G_8	DK2	1100	17	Only operates/offers for time units between 5am and 10pm
RoskildeCHP	G_9	DK2	300	44	Operates/offers for all time units
RoskildeCHP	G_{10}	DK2	380	40	Operates/offers for all time units
Avedøvre	G_{11}	DK2	360	37	Operates/offers for all time units
Avedøvre	G_{12}	DK2	320	32	Operates/offers for all time units
BlueWater	G_{13}	DK2	750	5	Operates/offers for all time units
BlueWater	G_{14}	DK2	600	12	Operates/offers for all time units
CoalAtLast	G_{15}	DK2	860	235	Operates/offers for all time units

Table 5: Wind producers

Supplier Name	**Supplier id.**	**Quantity [MWh]**	**Support**	**Support [€/MWh]**
WestWind1	WW_1	80% of predicted production	None	0
WestWind2	WW_2	20% of predicted production	Premium	17
EastWind1	EW_1	10% of predicted production	Feed-in Tariff	20
EastWind2	EW_2	90% of predicted production	Premuim	12

Table 6: Revenues in € for each generator in the two regions, DK1 and DK2

DK1	G_1	G_2	G_3	G_4	G_5	G_6	G_7	WW_1	WW_2
	6021096	9653058	3900	2655720	764520	23383836	0	41581767.2	19569049.8

DK2	G_8	G_9	G_{10}	G_{11}	G_{12}	G_{13}	G_{14}	G_{15}	EW_1	EW_2
	8325528	0	7720	380048	1628288	16709745	12270492	0	1279062	13953363.3