Regulated Transmission Expansion in Electricity Networks: the Effects of Fluctuating Demand and Wind Generation

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We study the performance of different regulatory regimes for the expansion of electricity transmission networks in the light of realistic demand patterns and fluctuating wind power. In particular, we analyze the relative performance of the combined merchant-regulatory HRV mechanism regarding welfare results and network expansion. We find that welfare outcomes and optimal network extension depend on the representation of demand and of wind generation. Both demand and wind fluctuations considerably increase the requirement for network upgrades. Under simplifying assumptions, the benefits of the HRV mechanism are modest compared to cost regulation or an approach without regulation. Yet the benefits of the HRV mechanism substantially increase in the light of fluctuating demand and wind patterns. Accordingly, the real-world advantages of HRV may be even larger than suggested by previous analyses, which were based on simplifying assumptions. Our results also suggest that HRV's characteristics may be favorable regarding future large-scale integration of fluctuating renewables into transmission networks.

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1 Introduction

Growing shares of fluctuating wind power increase the need for electricity transmission network expansion. At the same time, the natural monopoly character of transmission networks requires economic regulation of expansion investments. In this article, we study the behaviour of different regulatory regimes for transmission network expansion in the light of realistic demand patterns and fluctuating wind power generation. In particular, we are interested in the the combined merchant-regulatory Hogan-Rosellón-Vogelsang (HRV) mechanism and its relative performance compared to a welfare-maximizing benchmark, a non-regulatory approach, and cost regulation.

We apply the mechanisms to a stylized model of the central European transmission network. The transmission model represents real load flows, which allows to include loop flows and other special characteristics of electricity networks. In contrast to earlier applications of the HRV mechanism, we explicitly include both an hourly time resolution and fluctuating wind power, which substantially increases the real-world applicability of the approach. We solve the model numerically and compare welfare outcomes and the optimal levels of network expansion for different cases that vary with respect to demand representation and wind power fluctuations.

Our main finding is that both welfare results and network extension depend on the representation of demand and wind power. Compared to a simplified setting, both real-world demand and fluctuating wind patterns substantially increase the optimal amount of network extension. They also increase the difference between the welfare-maximizing solution and HRV outcomes. Yet the HRV mechanism is relatively robust against fluctuations. In contrast, the performance of both the approach without regulation and with cost regulation decrease substantially in the light of fluctuating demand and wind power. Accordingly, the real-world benefits of HRV may be even larger than suggested by previous, simplified analyses.

The remainder is structured as follows. Section 2 reviews the relevant literature. Sections 3 and 4 introduce the model and its application to a stylized central European example. Results are discussed in section 5. The last paragraph summarizes and concludes.

2 Literature

There are two main distinct analytical approaches to transmission investment: one employs the theory based on long-term financial transmission rights (LTFTR, merchant approach), while the other is based on the incentive regulation hypothesis (performance-based-regulation, PBR, approach). The PBR approach to transmission expansion relies on incentive regulatory mechanisms for a transmission company (Transco). One example is Vogelsang (2001) where price-cap regulation solves the duality of incentives for the transmission firm both in the short run (congestion) and in the long run (investment in network expansion). Equilibrium for this duality has been studied by the peak-load pricing literature: in equilibrium, the per-unit marginal cost of new capacity must be equal to the expected congestion cost of not adding an additional unit of capacity.[2] Alternative regulatory PBR approaches provide the firm with incentives to make efficient investment decisions through penalizing congestion.[3] In the international practice, PBR schemes for transmission expansion have been applied in England, Wales and Norway to guide the expansion of the transmission network.

In Vogelsang (2001) two-part tariff regulatory model, incentives for efficient investment in the expansion of the network are obtained by the rebalancing of fixed and variable charges

[2] Crew, Fernando and Kleindorfer (1995).

[3] Grande and Wangesteen (2000), Léautier, T.-O. (2000), and Joskow, P. and J. Tirole (2005).

while convergence to the steady state Ramsey-price equilibrium crucially depends on the type of weights used. Ramsey prices result from the solution of the program where a regulator seeks to maximize social welfare subject to the individual rationality constraint of a firm with increasing returns to scale. The prices are such that they differ from marginal cost inversely proportionally to the elasticity of demand. A Laspeyres index weight (previous period quantity weight) promotes intertemporal convergence of transmission tariffs to Ramsey prices, while average revenue weights (endogenous current period quantity weights) cause divergence from the Ramsey equilibrium. [4]

The merchant approach to transmission expansion is based on auctions of LTFTRs. The long-run concept is important for transmission expansion projects for investors. Such projects usually have an installed lifetime of approximately 30 years, so that auctions allocate FTRs with durations of several years. Incremental LTFTRs implicitly define property rights. FTR auctions are carried out within a bid-based security-constrained economic dispatch with nodal pricing of an independent system operator (ISO). The ISO runs a power-flow model that provides nodal prices derived from shadow prices of the model's constraints. FTRs are subsequently derived as hedges from nodal price differences. Externalities in electricity transmission are mainly due to loop flows which arise from interactions in the transmission network. The effects of loop flows imply that transmission opportunity costs and pricing critically depend on the marginal costs of power at every location in the network. Loop flows generate negative externalities on property-right holders. In the merchant approach, the ISO retains some capacity or FTRs in order to deal with such externalities. Equivalently, the agent making an expansion is required to 'pay back' for the possible loss of property rights of other agents.[5] In international practice, FTR auctions have been used in the North East of the USA (NYISO, PJM ISO, New England ISO).

A second-best standard that combines the merchant and PBR transmission models is proposed by Hogan, Rosellón and Vogelsang (2010), the "HRV" mecahnism. This is done in an environment of price-taking generators and loads. A crucial aspect is the redefinition of the transmission output in terms of incremental LTFTRs in order to apply the basic price-cap mechanism in Vogelsang (2001) to meshed networks within a power-flow model. The Transco intertemporally maximizes profits subject to a cap on its two-part tariff, but the variable fee is now the price of the FTR output based on nodal prices. Again, the rebalancing between the variable and fixed charges promotes the efficient expansion of the network. The HRV mechanism has already been tested in model-based analyses for simplified grids in Northwestern Europe and the Northeast USA.[6] The testing of the HRV regulatory model results in the Transco expanding the network so that prices develop in the direction of marginal costs. The nodal prices that were subject to a high level of congestion before the expansion converge to a common marginal price level. In any case, these results show that the HRV mechanism has the potential to foster investment in congested networks in an overall desirable direction.[7]

In this paper we expand the HRV model so as to incorporate the peculiarities of large-scale RES systems into the regulatory logic of the HRV model, giving rise to an "HRV-RES" model. One problem of PBR mechanisms is their inconsistency with timing issues of transmission networks. A framework based on the distinction of ultra-short periods, short periods and long periods would then be especially useful (Vogelsang, 2006). These timing

[4] Armstrong, Cowan and Vickers (1994).
[5] Bushnell and Stoft (1997), and Kristiansen and Rosellón (2006).
[6] Rosellón, J. and H. Weigt (2010), and Rosellón, J., Z. Myslíková, and E. Zenón (2010).
[7] The recently created Association of European Energy Regulators (ACER, to be fully operational in 2011) seeks to achieve similar goals for European transmission grids.

frameworks are especially relevant for the application of regulatory PBR mechanisms – such as the HRV model – to electricity systems characterized by fluctuating renewable feed-in. There exists a gap in the literature on such analysis that we would like to fill out in this paper. Likewise, we aim to also contribute with a novel application of combined regulatory-PBR mechanisms to the case of fluctuating and geographically dispersed renewables – in this case, fluctuating wind power in central Europe.

3 The Model

Table 7.1 in the Appendix lists all model sets and indices, parameters, and variables. The model formulation builds on Rosellón and Weigt (2011) and entails two levels. We assume welfare-maximizing dispatch of all generation capacities, carried out by an ISO (perfect competition). We further assume that there is a single Transco that owns all transmission lines and decides on network expansion. Note that the Transco holds a natural monopoly. The Transco's profit maximization constitutes the upper-level optimization problem. On the lower level, we formulate the ISO's welfare maximization problem as a mixed complementarity problem (MCP). The combination of lower and upper level problems forms a mathematical program with equilibrium constraints (MPEC).[8]

We model three different cases in which we assume the Transco to be not regulated (a kind of merchant transmission expansion), cost-regulated, or HRV-regulated. In addition, we set up a welfare-maximization benchmark, in which a social planner makes combined decisions on network expansion and dispatch. In this case, the upper-level problem represents the social planner's welfare-maximization problem. Assuming a standard linear demand function

$$p_{n,t,\tau} = a_{n,\tau} + m_{n,\tau} q_{n,t,\tau}, \tag{1.1}$$

the upper level problem for the welfare-maximizing benchmark is as follows:

$$\max wf = \sum_{t \in T} \left(\left(\sum_{\tau \in \mathrm{T}} \sum_{n \in N} \left(a_{n,\tau} q_{n,t,\tau} + \frac{1}{2} m_{n,\tau} (q_{n,t,\tau})^2 - \sum_{s \in S} c_s g_{s,n,t,\tau} \right) - \sum_{l \in L} ec_l P_{l,0} ext_{l,t} \right) \frac{1}{(1+\delta_s)^{t-1}} \right) \tag{1.2}$$

For the three different regulatory regimes, the upper level problems are represented by (1.3), (1.4), and (1.5):

$$\max \Pi_{noreg} = \sum_{t \in T} \left(\left(\sum_{\tau \in \mathrm{T}} \sum_{n \in N} \left(p_{n,t,\tau} q_{n,t,\tau} - \sum_{s \in S} p_{n,t,\tau} g_{s,n,t,\tau} \right) - \sum_{l \in L} ec_l P_{l,0} ext_{l,t} \right) \frac{1}{(1+\delta_p)^{t-1}} \right) \tag{1.3}$$

$$\max \Pi_{costreg} = \sum_{t \in T} \left(\left(\sum_{\tau \in \mathrm{T}} \sum_{n \in N} \left(p_{n,t,\tau} q_{n,t,\tau} - \sum_{s \in S} p_{n,t,\tau} g_{s,n,t,\tau} \right) + \sum_{l \in L} ec_l P_{l,0} ext_{l,t} \delta_r \right) \frac{1}{(1+\delta_p)^{t-1}} \right) \tag{1.4}$$

$$\max \Pi_{HRV} = \sum_{t \in T} \left(\left(\sum_{\tau \in \mathrm{T}} \sum_{n \in N} \left(p_{n,t,\tau} q_{n,t,\tau} - \sum_{s \in S} p_{n,t,\tau} g_{s,n,t,\tau} \right) + fixpart_t - \sum_{l \in L} ec_l P_{l,0} ext_{l,t} \right) \frac{1}{(1+\delta_p)^{t-1}} \right) \tag{1.5}$$

In the cost regulation case, a fraction δ_r of line extension costs enters the profits function with a positive sign. This represents the fact that in the case of traditional "cost-plus" regulation not only the line extension costs are reimbursed, but also an additional profit is granted. Note that line investments are recovered by variable charges (congestion rents) in the noreg case, but by a transfer from the regulator under costreg. In the HRV case, extension costs are partly

[8] Hobbs et al. (2000) were among the first to apply an MPEC approach to power market modelling.

recovered by congestion rents and partly by the fix part. An additional condition is required to set a cap on the fix tariff part chosen by the regulated Transco. It includes the previously mentioned Laspeyres weights (previous period quantity weights):

$$\sum_{n\in N}\sum_{\tau\in T}\left(p_{n,t+1,\tau}q_{n,t,\tau} - \sum_{s\in S} p_{n,t+1,\tau}g_{s,n,t,\tau} \right) + fixpart_{t+1} \\ \leq \sum_{n\in N}\sum_{\tau\in T}\left(p_{n,t,\tau}q_{n,t,\tau} - \sum_{s\in S} p_{n,t,\tau}g_{s,n,t,\tau} \right) + fixpart_{t} \tag{1.6}$$

In all cases, there is an inter-period constraint on line capacities:

$$P_{l,t+1} = P_{l,t} + P_{l,0} \cdot ext_{l,t} \tag{1.7}$$

The lower level dispatch problem consists of equations (1.8)-(1.15). They represent an MCP formulation of the ISO's constrained welfare maximization problem, which is provided in the Appendix. Note that the MCP includes constraints on line flows, energy balance and generation constraints, as indicated by (1.11), (1.12), (1.13), and (1.14). The model represents real load flows between nodes. The formulation largely follows Leuthold et al. (2008).

$$a_{n,\tau} + m_{n,\tau}q_{n,t,\tau} + p_{n,t,\tau} \leq 0 \quad \perp q_{n,t,\tau} \geq 0 \tag{1.8}$$

$$-c_{n,s} - p_{n,t,\tau} - \lambda_{4,n,s,t,\tau} \leq 0 \quad \perp g_{n,s,t,\tau} \geq 0 \tag{1.9}$$

$$-\sum_{l\in L}\lambda_{1,l,t,\tau}H_{l,n} + \sum_{l\in L}\lambda_{2,l,t,\tau}H_{l,n} + \sum_{nn} p_{nn,t,\tau}B_{nn,n} - \lambda_{5,n,t,\tau}slack_n \leq 0 \quad \perp \Delta_{n,t,\tau} \geq 0 \tag{1.10}$$

$$\sum_{n} H_{l,n}\Delta_{n,t,\tau} - P_{l,t} \leq 0 \quad \perp \lambda_{1,l,t,\tau} \geq 0 \tag{1.11}$$

$$-\sum_{n} H_{l,n}\Delta_{n,t,\tau} - P_{l,t} \leq 0 \quad \perp \lambda_{2,l,t,\tau} \geq 0 \tag{1.12}$$

$$\sum_{s} g_{n,s,t,\tau} - \sum_{nn} B_{n,nn}\Delta_{nn,t,\tau} - q_{n,t,\tau} = 0 \quad , \ p_{n,t,\tau} \ free \tag{1.13}$$

$$g_{n,s,t,\tau} - \overline{g}_{n,s} \leq 0 \quad \perp \lambda_{4,n,s,t,\tau} \geq 0 \tag{1.14}$$

$$slack_n\Delta_{n,t,\tau} = 0 \quad , \ \lambda_{5,n,t,\tau} \ free \tag{1.15}$$

Combining the upper- and lower-level problems results in four MPECs:

- Welfare-maximizing benchmark (wf-max): equations (1.2) and (1.7)-(1.15)
- No regulation (noreg): (1.3) and (1.7)-(1.15)
- Cost regulation (costreg): (1.4) and (1.7)-(1.15)
- HRV regulation (HRV): (1.5)-(1.15)

4 Model application

The four MPEC problems are implemented in the General Algebraic Modeling System (GAMS) and numerically solved with the commercial solver CONOPT. In addition, a case is included in which extension is not possible. We apply the model to a stylized transmission network of central Europe, which includes seven country nodes in Germany, France, Belgium and the Netherlands, eight auxiliary cross-border nodes and twenty lines (Figure 4.1). The same network has been used in earlier power market model applications (Neuhoff et al. 2005, Rosellón and Weigt 2011).

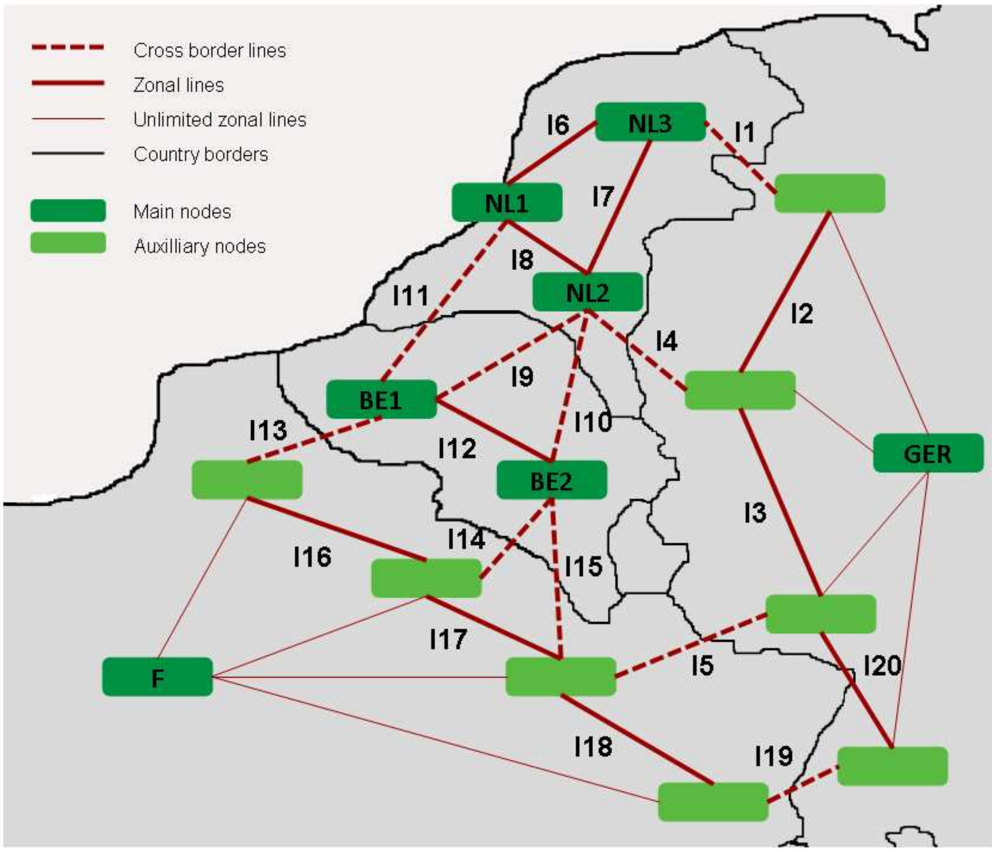

Figure 4.1: The stylized central European transmission network

We include eight power generation technologies. Table 4.1 lists variable generation costs and overall installed capacity in the stylized network (Entso-E, Eurostat, own calculations). Table 7.2 in the Appendix shows nodal generation capacities. We assume that not all installed conventional generation capacity is available any given point in time in order to reflect outages, seasonal maintenance and other restrictions. As for wind, we assume a capacity factor of 20%.

Table 4.1Generation capacity and variable costs

Technology	Variable generation costs in €/MWh	Overall capacity
Nuclear	10	84,408
Lignite	20	21,733
Hard coal	22	52,615
CCGT	30	10,872
Gas turbine	45	21,915
Oil	60	19,183
Hydro	0	15,652
Wind	0	47,694

We solve the model for three different cases that vary with respect to the time resolution of demand and wind generation. Table 4.2 provides an overview of the different cases. In the "Static" case, we assume average yearly demand levels, prices and wind generation. In the "DRes" case, demand is modeled on an hourly basis for six representative days of the year. We include both a weekday and a weekend day for each of three distinctive demand periods: summer (April to September), winter (November to February) and a shoulder period (March and October). We extrapolate to the whole year by weighting the six days with suitable factors. “WindRes” extends “DRes” by adding a fluctuating wind generation pattern. This allows us to separate the effects of demand fluctuations and wind power fluctuations.

Table 4.2: Overview of different cases

Case	Representation of demand	Wind generation
Static	Yearly average	Yearly average
DRes	144 hours, representing six characteristic days of the year	Yearly average
WindRes	144 hours, representing six characteristic days of the year	Fluctuating pattern

Table 4.3 lists nodal reference demands for the static case. These average demand levels have been calculated from hourly ENTSO-E data for 2009. As Rosellón and Weigt (2011), we assume a yearly average reference price $\overline{p}_{\tau}$ of €30/MWh and a price elasticity of demand ε of -0.25 at all nodes in the Static case. Average wind generation is assumed to equal 20% of installed wind capacity.

Table 4.3: Nodal reference demands in the static case

Node	Internal code	Country	Reference demand in MW
GER	n1	Germany	52.941
F	n2	France	55.748
BE1	n6	Belgium 1	4.426
BE2	n3	Belgium 2	5.289
NL1	n4	Netherlands 1	4.749
NL2	n5	Netherlands 2	5.001
NL3	n7	Netherlands 3	2.421

In the “DRes” case, nodal reference demand is modeled on an hourly basis. We group ENTSO-E demand data for 2009 in six different categories (weekdays and weekend days during summer, winter, and the shoulder period) and calculate average values. As shown in Figure 4.2, this results in 144 hours which adequately represent the whole year. The weighted average of these 144 hourly values results again in the reference demand levels of the Static case. In order to determine appropriate reference prices for the 144 hours, we take hourly German EEX spot prices for a whole year, group them into the six categories, and calculate averages. We then determine how these averages fluctuate around the (weighted) average price and apply the same pattern to the assumed average price of 30 €/MWh of the Static case. Thus, the weighted average of the resulting 144 hourly reference prices equals the value of the Static case. Figure 4.3 shows the resulting reference price pattern.

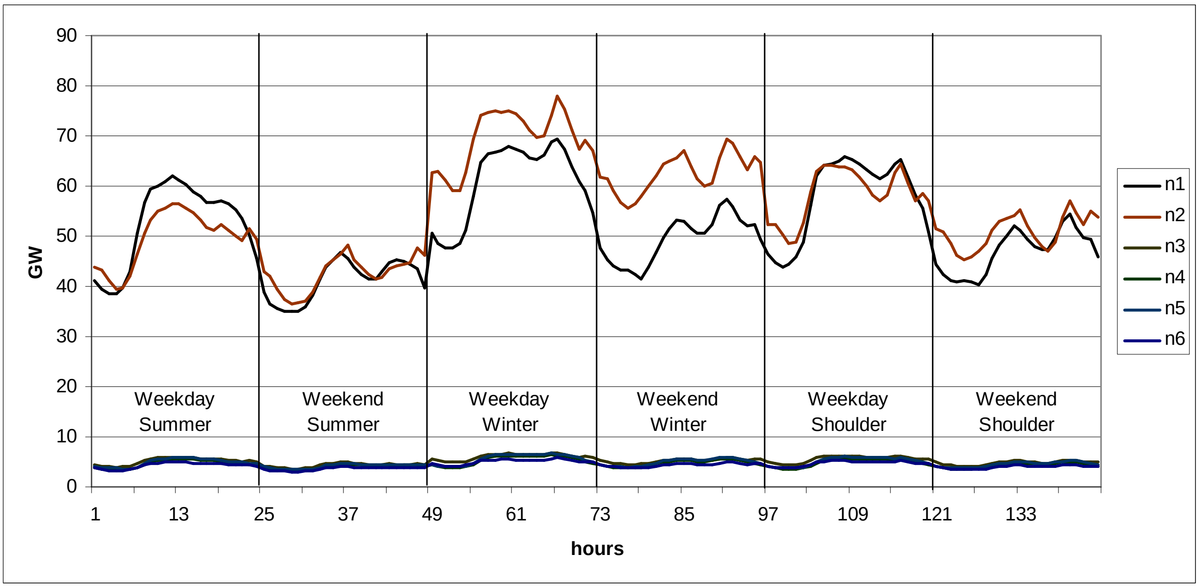

Figure 4.2: Hourly nodal reference demand for the DRes and WindRes cases

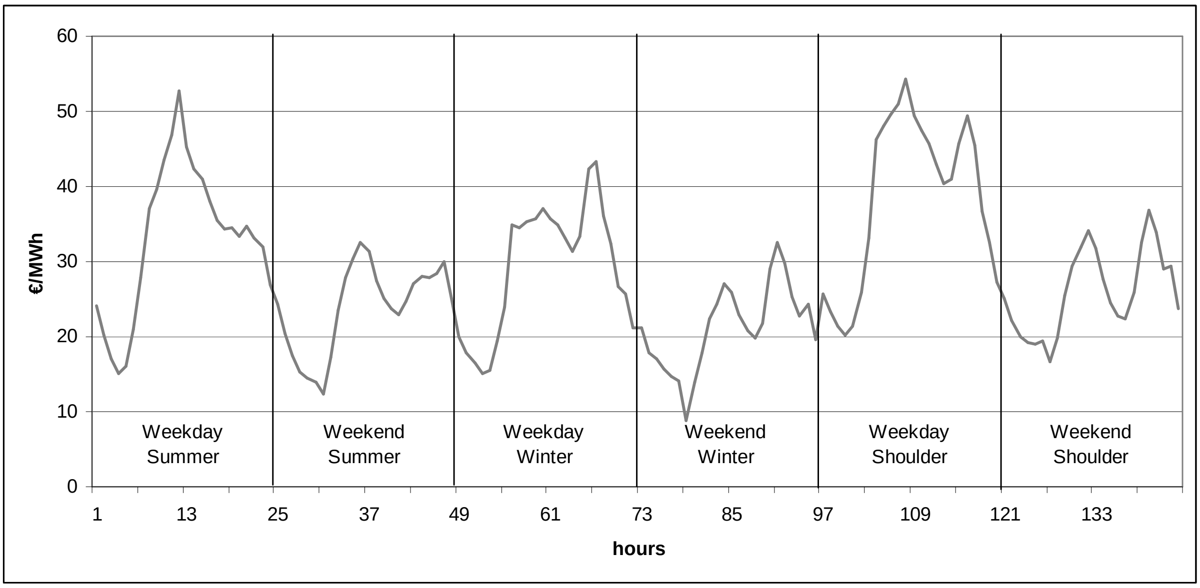

Figure 4.3: Hourly reference prices for the DRes and WindRes cases

For the "WindRes" case, we generate a fluctuating pattern with two extreme peaks (80% of installed capacity online in some periods, 100% of capacity offline in others). On average, the pattern leads to the same overall wind feed-in as in the "Static" and "DRes" cases. Figure 4.4 shows the wind pattern in the context of overall reference demand. Note that the resulting pattern is completely unrelated to demand levels. It should also be made clear that the wind pattern is not intended to resemble real-world hourly wind generation. Rather, it is intended to represent the characteristics of fluctuating wind generation on a yearly average. Over the 144 hours, many combinations of demand and wind generation occur, for example high wind / low demand or low wind / high demand. Although the approach is rather coarse, it captures the essentials of wind power fluctuations quite well.

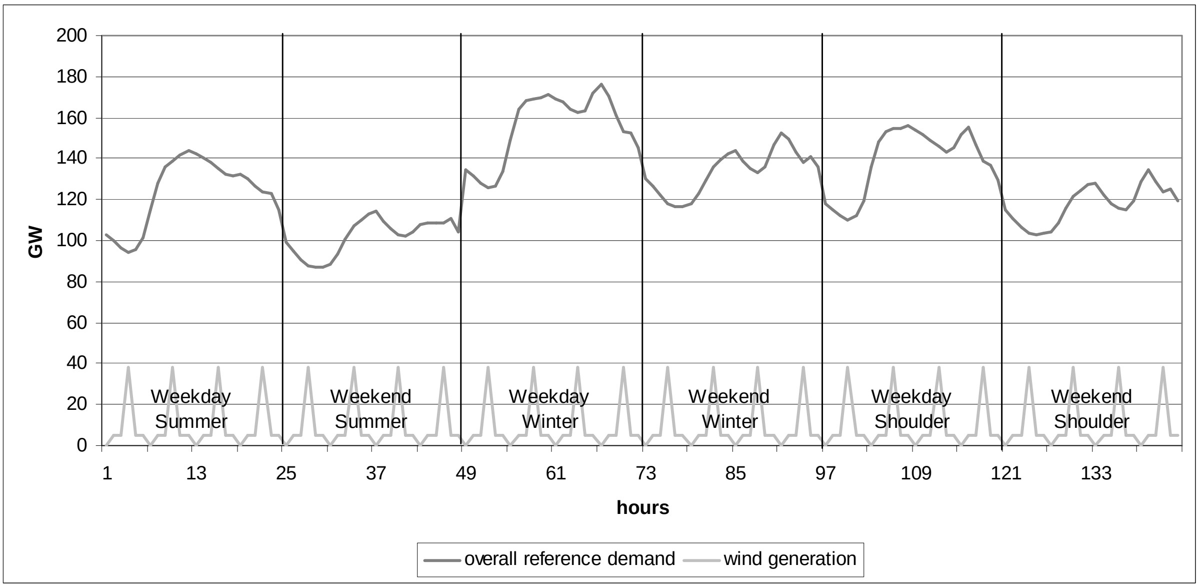

Figure 4.4: Wind generation and overall reference demand in WindRes

We solve the model for six years, i.e six regulatory time periods. Network expansion may start in the first period, but will be effective only in the second one. In order to summarize results over different years, we apply a social discount rate δ_s of 4% to all welfare-related measures and a private discount rate δ_p of 8% to the Transco's profit maximization. As for the rate of return regulation, we assume a rate δ_r of 0. In other words, the Transco's line extension investments are reimbursed without additional profits.

5 Results

5.1 The Static case

Table 5.1 summarizes results for the Static case.[9] Network expansion always increases welfare compared to a situation in which extension is not possible. As expected, welfare is highest in the welfare-maximization benchmark. HRV regulation results in welfare outcomes very close to this benchmark. Both costreg and noreg lead to slightly lower welfare results. Likewise, wf-max leads to the highest network extension, followed by HRV, costreg and noreg. Congestion rents are lowest in the welfare-maximizing case, followed by HRV. Under cost regulation and in the case of no regulation, congestion rents even increase compared to the case without extension. Transco profits are highest under HRV because of the additional fixed part. Transcos should thus have a preference for HRV regulation.

Table 5.1: Results for the Static case

	Welfare (bn €)	Congestion rents (bn €)	Transco profit (bn €)	Extension (GW)
No extension	460.08	2.30	2.11	-
wf-max	463.15	0.47	0.47	2.9
noreg	462.90	2.81	2.55	2.0
costreg	462.91	2.81	2.56	2.1
HRV	462.97	2.16	3.21	2.8

Under all regulatory regimes, the major extension takes place at the border Germany-Netherlands (line 4), followed by France-Netherlands (lines 15, 13 and 14). Yet the time path

[9] In the following, welfare and congestion rents are always calculated with a social discount rate of 4%. Congestion rents are calculated with a private discount rate of 8%.

of extension differs. In the welfare-maximization benchmark, all line extensions take place in the first period. The same is true for the cases noreg and costreg. In contrast, HRV regulation leads to incremental upgrades over the different regulatory periods.[10] This result is driven by the yearly determination of fixed parts according to equation (1.6).

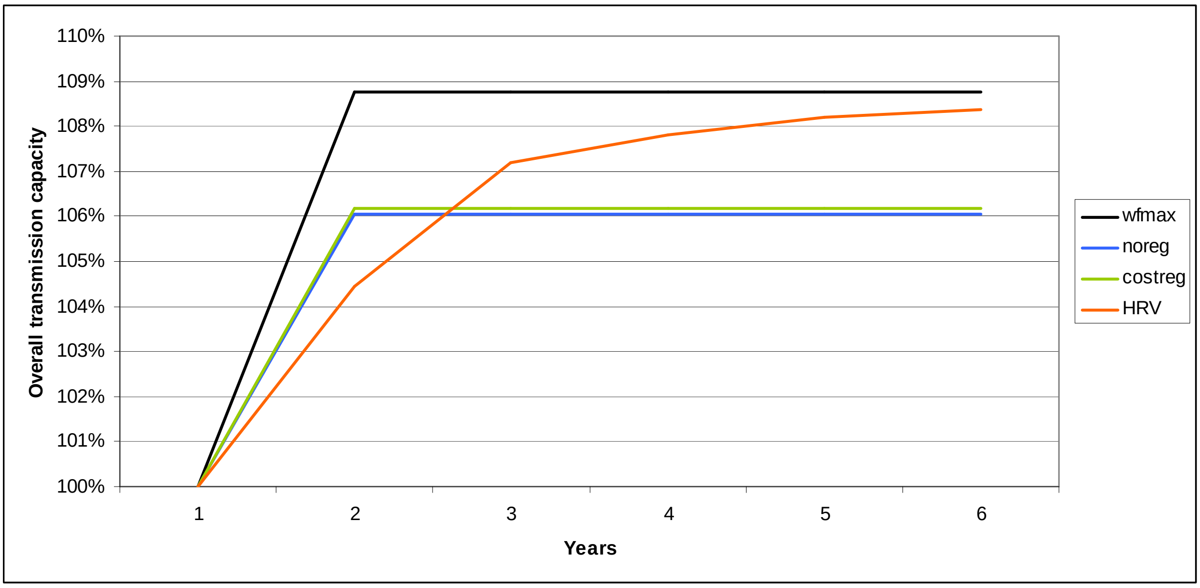

Figure 5.1: Transmission expansion paths for different regulatory schemes in the Static case

5.2 The case with demand fluctuations

Table 5.2 lists results for the DRes case. As in the Static case, network expansion always increases welfare compared to the setting without extension. Welfare is again highest in the welfare-maximization case, followed by HRV regulation, noreg and costreg. Congestion rents are again lowest in the welfare-maximizing case, and highest for noreg and costreg. Likewise, we find the highest Transco profits under HRV regulation and the highest network expansion in the wf-max case.

Table 5.2: Results for the DRes case

	Welfare (bn €)	Congestion rents (bn €)	Transco profit (bn €)	Extension (GW)
No extension	471.73	2.98	2.11	-
wf-max	473.81	0.69	0.68	8.5
noreg	472.47	3.10	2.83	0.9
costreg	472.39	3.14	2.87	0.9
HRV	473.49	1.99	3.42	6.0

Despite these general similarities, results substantially differ compared to the Static case. Fluctuating demand levels increase network congestion, particularly in peak hours. Accordingly, additional lines are being expanded. In contrast to the Static case, extension now takes place not only at the borders between Germany-Netherlands and France-Netherlands. In the wf-max case, extension in DRes also occurs between Germany and France (lines 19 and 5), as well as between Belgium and the Netherlands (lines 10 and 11). Table 5.3 lists relative differences between Static and DRes results. Demand fluctuations lead to slight increases in overall welfare, but to strong increases in congestion rents (except in the HRV case) and Transco profits. Moreover, fluctuating demand substantially increases optimal network

[10] Note that we allow for continuous line extension. In the real world, there may be considerable lumpiness of line investments.

expansion in the welfare-maximization benchmark and in the HRV case because of higher congestion. Interestingly, extension decreases in DRes compared to the Static scenario under cost regulation and in the case without regulation. Obviously, Transcos under noreg and costreg try to preserve as much fluctuation-related congestion rent as possible.

Table 5.3: Relative differences between Static and DRes

	Welfare (bn €)	Congestion rents (bn €)	Transco profit (bn €)	Extension (GW)
No extension	+3%	+29%	0%	-
wf-max	+2%	+47%	+45%	+190%
noreg	+2%	+10%	+11%	-53%
costreg	+2%	+12%	+12%	-58%
HRV	+2%	-8%	+7%	+115%

In the welfare-maximizing case, the large extent of network expansion leads to strong price convergence between the nodes. In particular, peak load prices are nearly equal over all nodes. Prices converge is slightly lower in off-peak periods and during weekends. In the HRV case, price convergence is also high for peak load periods (weekdays), but lower during weekends compared to wf-max. In contrast, price convergence is much smaller in the noreg case in all periods, as network extension is much lower in this case. The figures in section 7.4 in the Appendix provide additional details.

5.3 The case with wind fluctuations

Table 5.4 lists WindRes results. Some general results do not change compared to DRes and Static: HRV is still closest to the welfare maximum in terms of welfare, congestion rents, and profit, when compared to the alternatives noreg and costreg. The welfare gains of network extension are now slightly higher than before: the difference between welfare results in the case of no extension and wf-max increases from €2.08 billion in DRes to €2.18 billion in WindRes. Overall welfare decreases slightly compared to DRes. This is because wind peaks heavily decrease prices in some hours, which leads to a large decrease in producer surplus.

Table 5.4: Results for the WindRes case

	Welfare (bn €)	Congestion rents (bn €)	Transco profit (bn €)	Extension (GW)
No extension	469.61	2.80	2.11	-
wf-max	471.79	0.76	0.74	16.7
noreg	470.20	2.96	2.69	1.9
costreg	470.19	2.95	2.70	2.4
HRV	471.36	1.94	3.39	11.2

In the welfare optimum, overall extension is higher in WindRes than in the case with constant wind feed-in because of higher (temporary) congestion. In particular, capacity between Germany-Netherlands and Germany-France strongly increases in wf-max due to high German wind capacity. Moreover, there are additional line extensions within the Netherlands (line 6) and within France (line 17). Line extension under HRV also grows strongly compared to the non-fluctuating DRes case, although it is less close to welfare optimal extension than in DRes. Extension in the noreg and costreg cases remains very low. Consequently, price convergence across nodes is nearly perfect in wf-max, but hardly existent in noreg (Figures in section 7.5).

5.4 Comparison of welfare and extension over all cases

Table 5.5 compares welfare and network extension results relative to the welfare-maximizing benchmark for the three cases. A realistic representation of demand fluctuations increases the gap between the welfare-maximizing solution and the welfare outcomes of the different regulatory cases. Fluctuating wind power further increases this gap. HRV welfare outcomes, however, are closer to the optimum than the no regulation or the cost regulation outcomes in all cases. We thus conclude that HRV welfare results are more robust against fluctuations of demand and wind power than the other alternatives.

We find the same effects for overall extension outcomes, but much more pronounced. HRV regulation achieves nearly 96% of the welfare-maximizing extension in the simplified static case. This value is close to the results of Rosellón and Weigt (2011). HRV, however, reaches only 71% of the welfare-maximizing line extension in the case of fluctuating demand, and only 67% in case of additional wind fluctuations. Yet HRV extension results are still much higher than the ones of the noreg and costreg cases, which are in the range of only 10-14% of the welfare-maximizing solution. In the light of realistic demand patterns fluctuating wind feed-in, the HRV mechanism thus leads to much higher network extension than the alternative options.

Table 5.5: Relative outcomes compared to wf-max

	Welfare			Overall extension		
	Static	**DRes**	**WindRes**	**Static**	**DRes**	**WindRes**
wf-max	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
noreg	99.95%	99.72%	99.66%	68.90%	11.07%	11.51%
costreg	99.95%	99.70%	99.66%	70.59%	10.24%	14.40%
HRV	99.96%	99.93%	99.91%	95.52%	70.70%	66.88%

6 Conclusions

Our results suggest that details matter in electricity transmission network modeling. A more realistic representation of demand and a consideration of fluctuating wind generation lead to additional congestion, which in turn increases network expansion requirements. In contrast, a simplified, static approach might systematically underestimate the need for transmission upgrades. The relative welfare performance of different regulatory regimes also depends on the representation of demand and wind power. While there are only small differences between the regimes in the simplified case, both welfare and extension outcomes vary much more in the DRes and WindRes cases.

Intriguingly, the properties of the HRV mechanism seem to be very robust against demand and wind fluctuations. HRV leads to the second-highest welfare and extension outcomes in all model runs. Moreover, HRV's relative performance compared to the approach without regulation and to cost regulation increases with fluctuating demand and wind power. Accordingly, HRV outcomes in real-world applications may be even more favorable compared to other regulatory regimes than suggested by previous, simplified model applications.

In the light of future large-scale wind integration, HRV has some favorable characteristics. Not only does it lead to high welfare results, but it also triggers relatively high network extension. In the real world, the large-scale integration of wind power is not only constrained by limited transmission capacities, but also by imperfect foresight and thermal ramping restrictions. Although we did not model these aspects, it is clear that larger network expansion is generally good for wind integration. In this respect, the HRV mechanism seems to be a much more promising option than an approach without regulation, i.e. a merchant approach.

While this article provides new insights into the relative performance of the HRV mechanism under realistic assumptions, several challenges remain. In particular, the effects of more realistic nodal wind patterns should be investigated. Moreover, additional constraints for wind integration like ramping constraints and imperfect foresight might be included. Last, but not least, a more general application could relax the assumption of perfect competition in generation and allow for zonal instead of nodal prices.

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7 Appendix

7.1 Sets and indices, parameters, variables

Table 7.1: Sets and indices, parameters, variables

Symbol	Description	Unit
Sets and indices:		
$n, nn \in N$	Nodes	
$l \in L$	Line	
$s \in S$	Generation technology (Nuclear, lignite, hard coal, CCGT, gas turbine, oil, hydro, and wind)	
$t \in T$	Regulatory time periods	years
$\tau \in T$	Dispatch time periods	hours
Parameters:		
$\overline{q}_{n,\tau}$	Reference demand	MW
$\overline{p}_{\tau}$	Reference price	€/MWh
$m_{n,\tau}$	Slope of demand function	
$a_{n,\tau}$	Intercept of demand function	
$\overline{g}_{n,s}$	Maximum hourly generation capacity	MWh
c_s	Variable generation costs	€/MWh
ec_l	Line extension cost factor	€
ε	Price elasticity of demand at reference point	
$P_{l,0}$	Initial line capacity	MW
$\overline{X}_l$	Line reactance	Ω
$H_{l,n}$	Flow sensitivity matrix	1/Ω
$B_{n,nn}$	Network susceptance matrix	1/Ω
$slack_n$	Slack node	
ec_l	Line extension cost factor	€
δ_s	Social discount rate	
δ_p	Private discount rate	
δ_r	Rate of return (cost regulation)	
Variables:		
wf	Overall welfare	€
Π_{HRV}	Transco profit under HRV	€
Π_{noreg}	Transco profit without regulation	€
$\Pi_{costreg}$	Transco profit under cost regulation	€
$q_{n,t,\tau}$	Hourly demand	MWh
$g_{n,s,t,\tau}$	Hourly generation	MWh
$p_{n,t,\tau}$	Hourly electricity price	€/MWh
$\Delta_{n,t,\tau}$	Voltage angle difference	
$\lambda_{1,l,t,\tau}$	Shadow price of positive line capacity constraint	
$\lambda_{2,l,t,\tau}$	Shadow price of negative line capacity constraint	
$\lambda_{3,n,t,\tau} = p_{n,t,\tau}$	Shadow price of market clearing constraint (electricity price)	
$\lambda_{4,n,s,t,\tau}$	Shadow price of generation capacity constraint	
$\lambda_{5,n,t,\tau}$	Shadow price of slack constraint	
$ext_{l,t}$	Line extension factor	
$P_{l,t}$	Line capacity	MW
$fixpart_t$	Fix charge of HRV regulation	€

7.2 ISO's constrained welfare maximization problem

$$\begin{aligned}
&\max_{\substack{q,g,\Delta,\\ \lambda_1,\lambda_2,p,\\ \lambda_3,\lambda_4,}} \sum_{t\in T}\left(\sum_{\tau\in \mathrm{T}}\sum_{n\in N}\left(\int_0^{q^*_{n,t,\tau}} p_{n,t,\tau}(q_{n,t,\tau})dq_{n,t,\tau} - \sum_{s\in S} c_s g_{s,n,t,\tau}\right)\frac{1}{(1+\delta_s)^{t-1}}\right) \\
&s.t. \quad \sum_n H_{l,n}\Delta_{n,t,\tau} - P_{l,t} \le 0 \qquad (\lambda_{1,l,t,\tau}) \qquad \forall l,t,\tau \\
&\qquad -\sum_n H_{l,n}\Delta_{n,t,\tau} - P_{l,t} \le 0 \qquad (\lambda_{2,l,t,\tau}) \qquad \forall l,t,\tau \\
&\qquad \sum_s g_{n,s,t,\tau} - \sum_{nn} B_{n,nn}\Delta_{nn,t,\tau} - q_{n,t,\tau} = 0 \quad (p_{n,t,\tau}) \qquad \forall n,t,\tau \\
&\qquad g_{n,s,t,\tau} - \bar{g}_{n,s} \le 0 \qquad (\lambda_{4,n,s,t,\tau}) \qquad \forall n,s,t,\tau \\
&\qquad slack_n\Delta_{n,t,\tau} = 0 \qquad (\lambda_{5,n,t,\tau}) \qquad \forall n,t,\tau
\end{aligned} \tag{1.16}$$

7.3 Generation capacity at different nodes

Table 7.2: Generation capacity at different nodes

	Nuclear	Lignite	Hard coal	CCGT	Gas turbine	Oil	Hydro	Wind	**Overall**
n1	20340	21153	28964	7758	10634	5517	1271	39713	**135350**
n2	58288	580	15822	0	124	11130	14381	4052	**104377**
n3	2713	0	2474	350	575	560	0	246	**6918**
n4	449	0	3968	249	4872	111	0	1146	**10795**
n5	0	0	253	0	1510	0	0	1146	**2909**
n6	2618	0	1134	810	1432	1865	0	246	**8105**
n7	0	0	0	1705	2768	0	0	1146	**5619**
Overall	**84408**	**21733**	**52615**	**10872**	**21915**	**19183**	**15652**	**47694**	**274072**

7.4 Price convergence in DRes

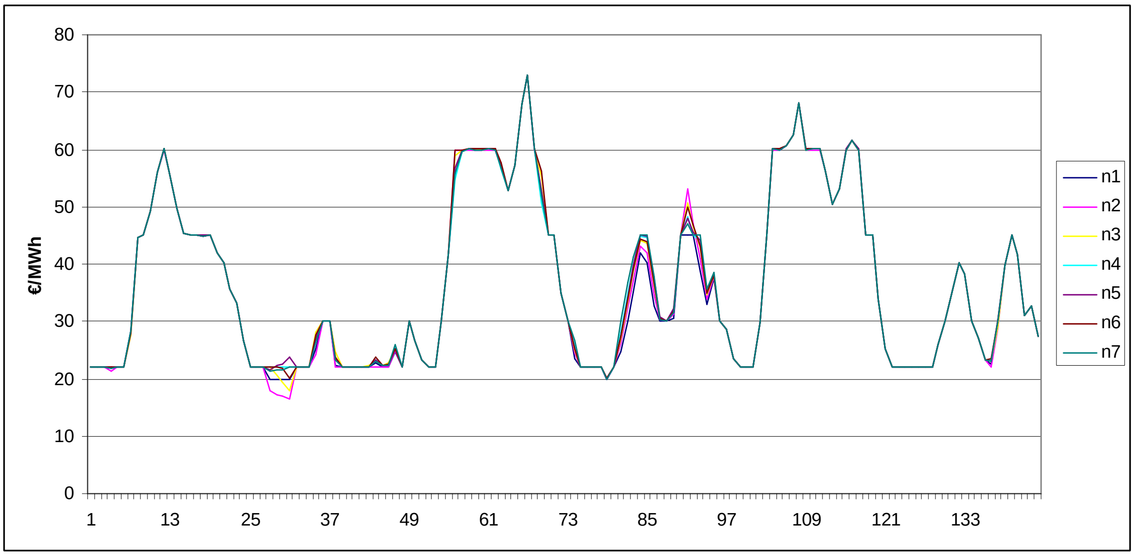

Figure 7.1: Price convergence for DRes wf-max

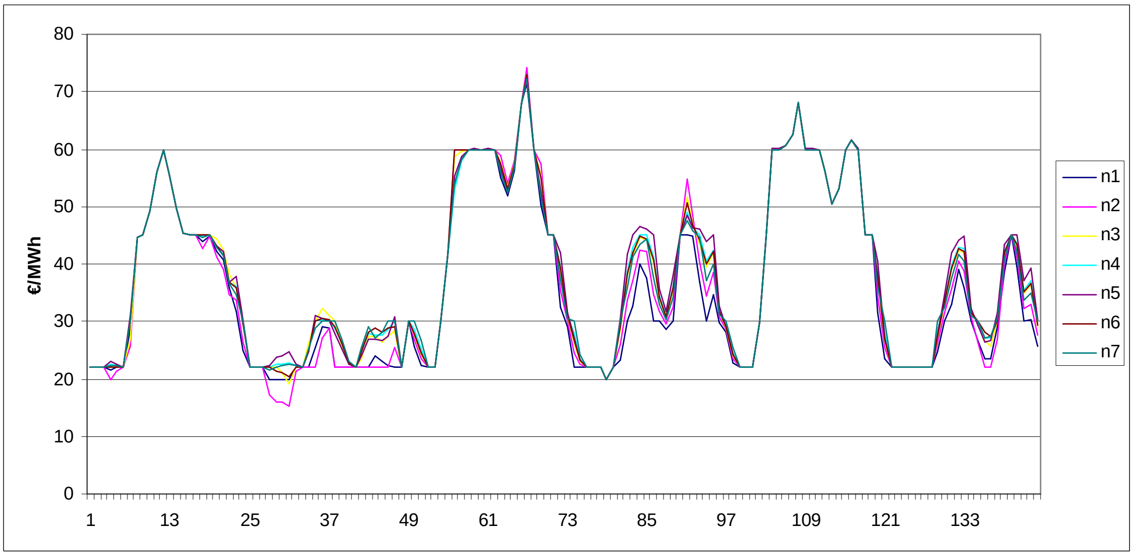

Figure 7.2: Price convergence for DRes HRV

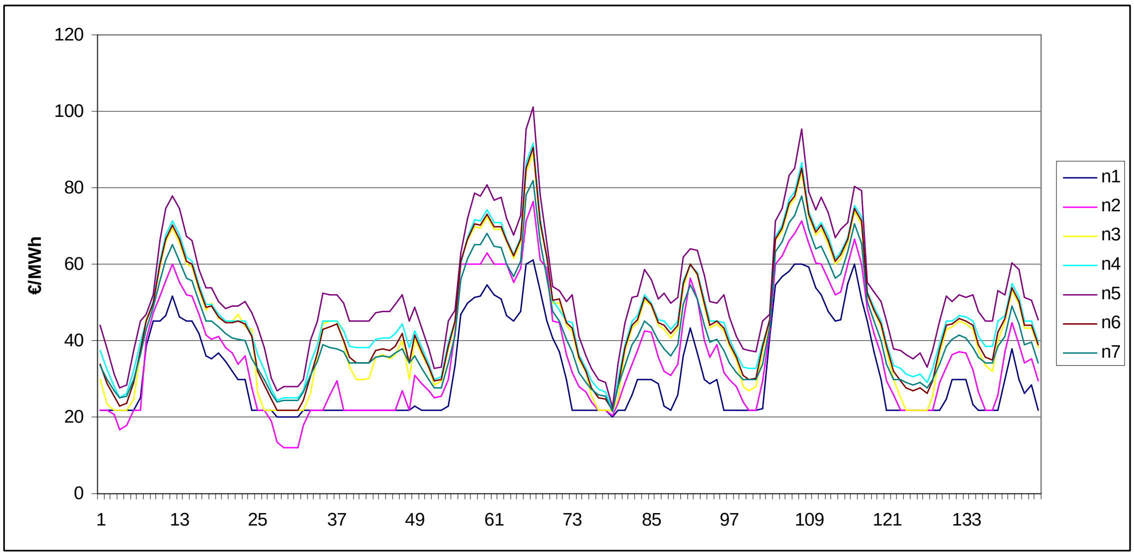

Figure 7.3: Price convergence for DRes noreg

7.5 Price convergence in WindRes

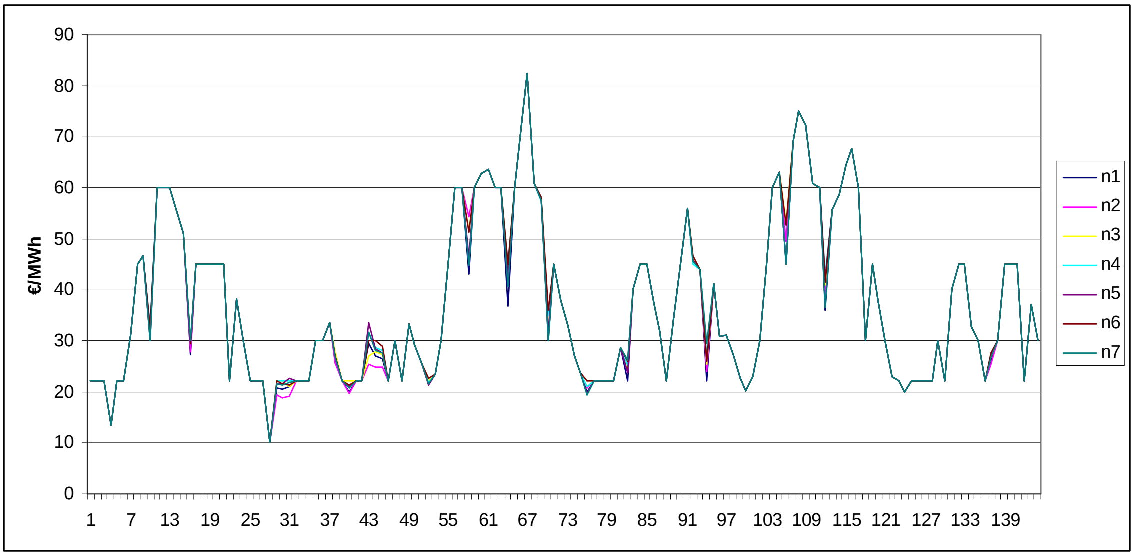

Figure 7.4: Price convergence for WindRes wf-max

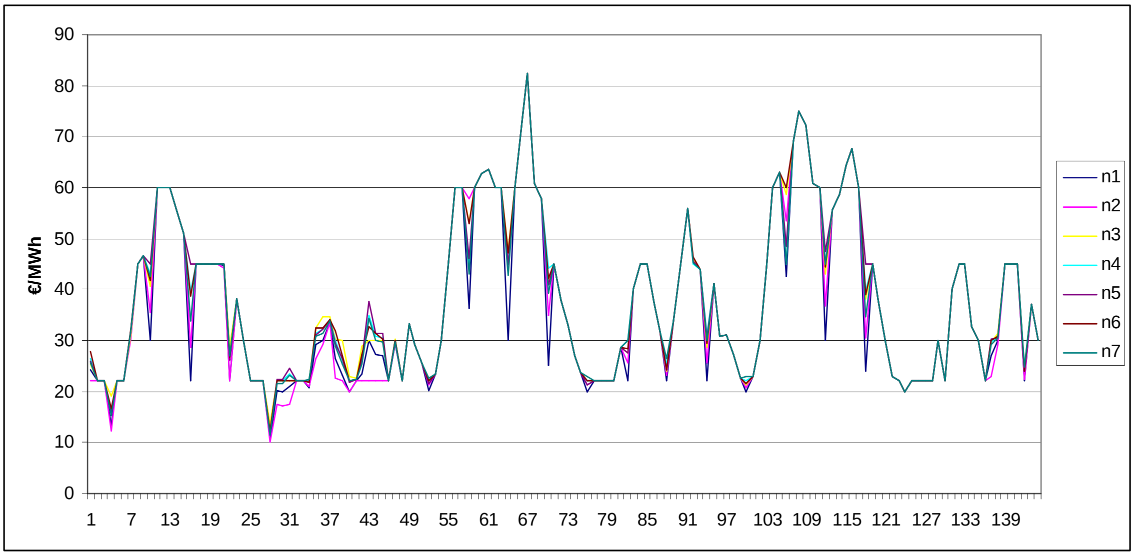

Figure 7.5: Price convergence for WindRes HRV

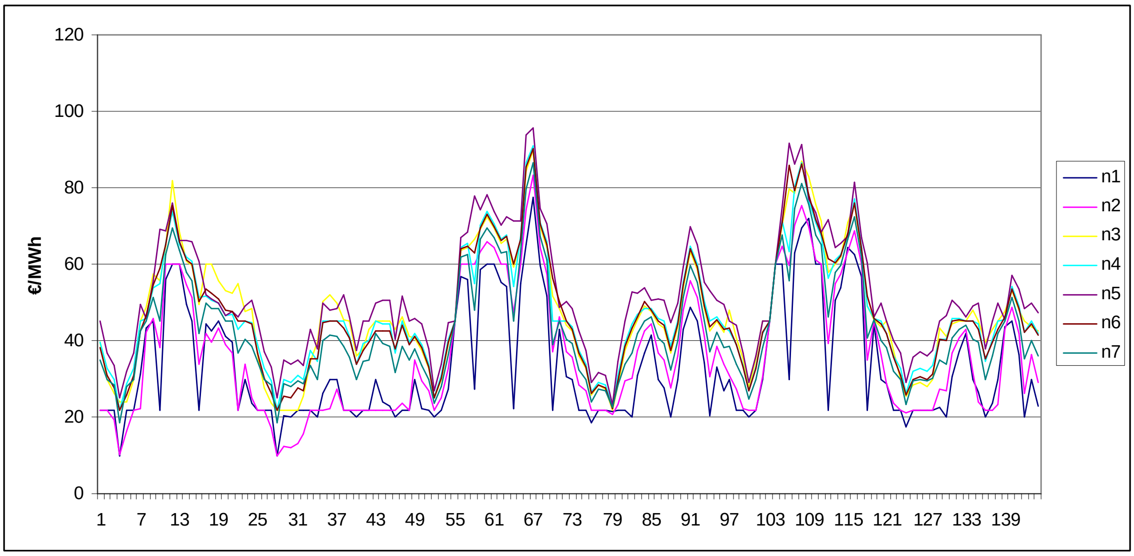

Figure 7.6: Price convergence for WindRes noreg