Optimal level of remuneration for capacity to ensure generation adequacy

- Case: Increased RES infeed & nuclear phase out -

Hanspeter Höschle[1], Cedric De Jonghe, Ronnie Belmans
KU Leuven, ESAT - Electa, Kasteelpark Arenberg 10 PB 2445, 3001 Heverlee, Belgium
Phone: +32 16 37 78 87 Fax: +32 16 32 19 85
EnergyVille, Dennenstraat 7, 3600 Genk, Belgium
VITO NV, Boeretang 200, 2400 Mol, Belgium

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1 Introduction

Power generators in the current wholesale market rely on the revenues from selling the produced electricity to cover their costs. According to the theory of electricity markets with marginal clearing price, bidding at marginal costs ensures the coverage of the variable cost while inframarginal rents are necessary to cover the fixed costs of the power generators. Peaking generators rely on price spikes or scarcity prices to fully cover there fixed costs (Stoft, 2002).

Insufficient revenues from the market lead to unprofitability of generation units and question their further operation. Moreover, uncertainties about satisfactory future revenues hamper investment in new generation units. As a consequence, the disappearance of existing units and a non-adequate replacement with new investment, also to cope with future growth, put a threat on system adequacy and security of supply.

Policy making to promote the increase of renewable energy sources (RES) leads to a large scale integration of intermittent generation that can offer its produced electricity at zero marginal cost or even lower. This has an influence on both the operating hours and revenues from selling electricity for existing conventional generation units. The merit order effect puts more pressure on the business model of these units.

At the same time, the discussion of the extent of future integration of nuclear power plants in the national generation mix is discussed. Germany and Belgium each agreed to phase out nuclear energy and decided on a stepwise shutting down of still existing units until 2022 respectively 2025.

To avoid generation adequacy in the (near) future and to cope with the problem of absent adequate investments, capacity remuneration mechanisms (CRMs) are widely discussed (e.g. Finon and Pignon (2008), Batlle and Pérez-Arriaga (2008), De Vries (2007), Roques (2008)). CRM can be implemented as policy instrument for ensuring adequate level of electricity generation (De Vries and Ramirez Ospina, 2012). It is understood as additional and complementary mechanism to the current market design (see Figure 1). Through remuneration of installed capacity, CRM create a revenue stream that is independent from the actual output but values the availability of a generation unit. On the long term, the remuneration reduces the necessity of price spikes to incentivize investments and ensures profitability of sparsely used generators. Moreover, CRM can be used to promote a desired transition towards a system without nuclear units and a larger penetration of RES. However, differing levels of remuneration per technology can have influence of investors and generators which might result in undesired outcome such as inefficient overpayment or creating inequality of opportunity.

This paper introduces a model to get insights in the electricity market and the behavior of power

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[1] Corresponding author: Hanspeter Höschle, hanspeter.hoschle@esat.kuleuven.be

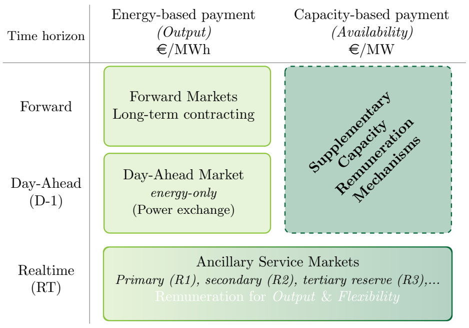

Figure 1: Remuneration of output and availability in market design with CRM

generators under changing conditions. The changing conditions include growth in demand and penetration of RES as well as an enforced nuclear phase out. This scenario is applied to understand the effect of revenues origin both from an energy market as well as from a CRM. While in reality, the design of the CRM might vary the model assumes simplified revenues streams based on the installed capacity expressed in €/MW.

The paper is structured as follows. Section 2 describes the power generator problem and its implementation in a two-step model. Afterwards, the case and scenario, including the model data is presented in section 3. The results of the case study are given section 4. The final section concludes the findings of this paper.

2 Methodology

The underlying methodology to analyze the effects of a CRM on the power generators behavior is the modeling of the generation and investment decision in a two-step model (see Fig. 2). In the first step the power generators are modeled as profit-maximizing market participants in a perfect competition framework. Perfect competition and absence of market distortions allow the prices to rise to any level necessary.

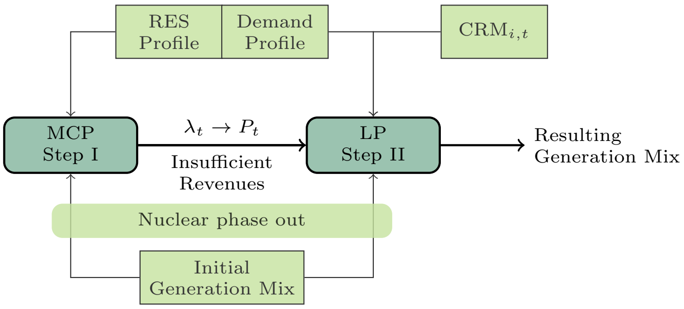

Figure 2: Model Structure

Four subsequent periods are modeled within one optimization representing each an investment period with the possibility for the generators to adapt. Exceptional, the first period does not include an investment decision but represents the initial state of the system, i.e. a brownfield approach. Each step in between two time periods (t_{inv}) can be understood as time leap. Also, each time period takes into account growth of demand and RES and is represented by the corresponding profiles. Each profile comes within an hourly temporal resolution and can be adapted in length to the scenario for computational reasons, one week to months. The total number of times steps ($t \in T$) equals then e.g. 4 periods * 24h * n days (see Fig. 3).

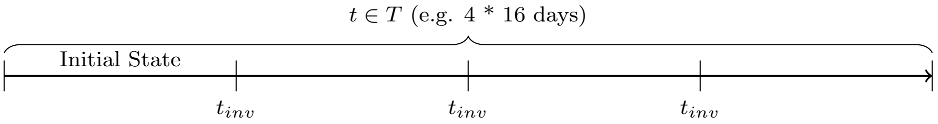

Figure 3: Model time line showing four time periods

Each generator in the market optimizes its on profit by deciding on the generation output as well as adaptation of its installed capacity. This can be in form of installing additional capacity or dismantling existing capacity. Technical limitations are taken into account and include ramping and maximum generation limits. Each power generator acts as price taker in the market. Its variable and fixed costs are offset by the revenues from the energy market and CRM.

The first step is modeled as mixed complementarity problem (MCP) connecting each power generator via the system balance equation. Next to the individual optimal behavior of the power generators, as a result the model gives the price profile necessary to ensure the profitability of each generator. The dual variable (λ_t) of the system balance includes both the prices resulting from variable costs of the marginal units as well as price spikes in time steps of scarcity.

In order to analyze situation of insufficient revenues from energy market, the price profile resulting from the MCP is modulated. According to observation of the prices at power exchanges, the prices are cut at a level below the necessary optimal level. This price cap is below the market cap and origins from interventions of regulators and cautious bidding behavior of power generators. It can be understood as implicit price cap and results in an adapted price profile (P_t).

The second step of the model includes the adapted price profile. As the price profile is an exogenous parameter, the power generators profit maximization results in a Linear program (LP). The insufficient revenues, due to the caped prices, result in less and inadequate incentives for power generators to enable system adequacy. The level of CRM can be varied to investigate the resulting reaction and therefore the effects on the installed capacity, i.e. the generation mix or energy not served, i.e. load shedding. The CRM can be equal for all power generators or graduated per technology.

Both, the MCP and LP model are written in GAMS (GAMS, 2013). For solving the MCP the PATH MCP solver (Dirkse and Ferris, 1995) is used. The LP is solved with the ILOG CPLEX solver (CPLEX, 2013).

A more detailed description and mathematical formulation of the model is given in (Höschle, 2014a) and (Höschle, 2014b).

3 Case & Scenario

The case of this paper investigates the changing market conditions including a strong increase of the penetration of RES feed-in and an enforced stepwise nuclear phase out. This section discusses the input data used in the model, the details of the scenario and the two particular cases analyzed.

3.1 Input Data

Within each time period a demand and RES profile taken from the Belgian system forms the baseline of the input data. Figure 4 shows the profiles for demand and RES as well as the resulting residual load that must be covered by the conventional power generators. Both profiles have an hourly temporal resolution and origin from March 2013 (ELIA, 2013).

The generation mix is represented by four technologies, i.e. base, mid, peak and high peak. The technologies differ in their technical and economic characteristics. An overview is given in Table 1.

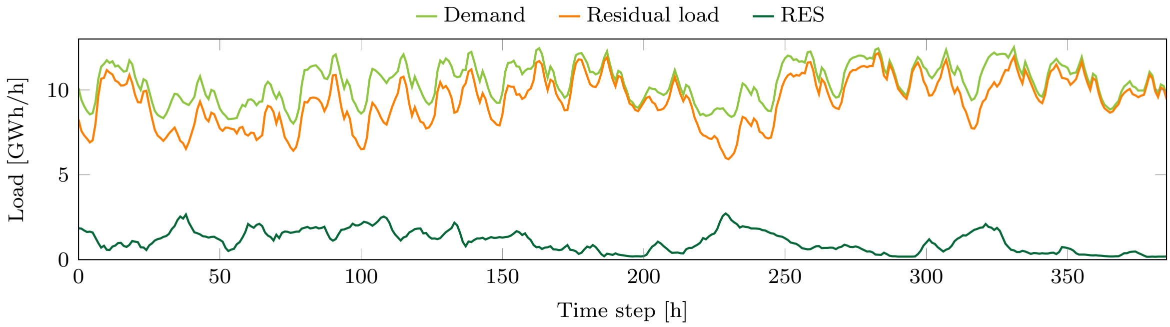

Figure 4: Input Profiles for 1 time period (16 days)

The technical factors include the ramping rates as well as the initial installed capacity. The economic characteristics include the variable and fixed costs (De Jonghe, 2011). Moreover, the table shows the possible increase and decrease of capacity. For the base technology, an increase is not permitted as a stepwise phase out of 2000 MW per period is enforced. Demand response or storage technologies are omitted. Demand is considered inflexible and price inelastic.

Table 1: Technologies and scenario setup

Tech [#]	VC_i [€/MWh]	FC_i [(€/MW)/h]	CAP_i [MW]	$RAMP_i^+$ [%/h]	$RAMP_i^-$ [%/h]	Possible increase	Possible decrease
Base	6.00	39.80	6621	0.083	0.083	×	-2000[MW]
Mid	35.00	11.40	3106	0.200	0.200	✓	✓
Peak	50.00	4.56	1608	0.500	0.500	✓	✓
High Peak	72.00	2.85	831	1.000	1.000	✓	✓

3.2 Scenario

The scenario for this case study includes a moderate growth of 2% of the demand for each time step. This goes in line with the forecast demand growth for the Belgian system (ENTSO-E, 2012). Note that a step in between time periods does not necessarily represent a yearly step. Table 2 shows how the peak and base demand evolves over the four periods.

The exogenous RES profile is also taken from the Belgian system and nominated for an initial installed capacity of 2 000 MW wind and 2 500 MW solar. For the time periods two to four an annual growth of +20% is assumed, i.e. increase of installed capacity of +900 MW. In the last period, this equals a share in generation of 15.56% originating from RES. The effect of RES on the residual peak and base demand is also shown in Table 2.

Finally, the nuclear phase out is implemented as an enforced stepwise reduction of the installed capacity of the base load technology. Starting from an initial capacity of 6 621 MW, i.e. 54.4% of total installed capacity, it is reduced by 2 000 MW per time step to a remainder of 621 MW in the last time step. Again the steps between time periods are not necessarily yearly steps.

Table 2: Demand and RES growth in the four time periods

Time	Demand Profile			RES profile			Residual		Installed
Period	Peak	Base	Growth	Peak	Base	Growth	Peak	Base	Nuclear
1 (Initial)	12511.75	8024.42	-	2716.87	174.39	-	12165.86	5922.41	6621
2	12761.99	8184.91	+2%	3260.24	209.27	+20%	12357.82	5574.04	4621
3	13012.22	8345.40	+4%	3803.62	244.15	+40%	12549.78	5225.68	2621
4	13262.45	8505.89	+6%	4346.99	279.02	+60%	12741.73	4877.31	621

3.3 CRM

The level of CRM and its effects is investigated with to different cases. Case I represents the reference case where the payments through the CRM equals the missing revenues due to the price cap. Case II represents a situation in which mid technologies are overcompensated assuming that they are favored to replace the absent capacity of the base technology.

3.3.1 Case I: Optimal level of payment

The first case is calculated as reference case. The price spikes that occur in the MCP per time period are capped at $p_{cap} = 300$ €/MWh. This goes in line with the maximum prices seen over the last years at the Belgian Power Exchange Belpex (Belpex, 2013). In order to obtain the same results in terms of generation adequacy the missing revenues originating from the capping are replaced by an additional payment for installed capacity. In Case I, the payment is equal for all technologies. The optimal level of payment can be derived from (1). To fit the model, the $CRM_{i,t}$ is expressed in (€/MW)/h per technology.

$$(\lambda_t^{max} - p_{cap}) * gen_{i,t} = (FC_{peak} * T + VC_{peak} - p_{cap}) * gen_{i,t} = CRM_{i,t} * T * cap_{i,t} \tag{1}$$

Following the data used in this paper, the level of optimal payment can be calculated to 2.25635 (€/MW)/h. Applied for an annual payment, this results in an annual steady revenue stream of 19766 (€/MW)/a for each generator.

3.3.2 Case II: Increased payment for mid load technologies

In the second case an increased payment for the mid load technologies is implemented. This relates to the policy decision to support this technology as it has to be incentivized to replace the phased out base technologies. This should ensure that there is enough installed capacity to cope with the increased demand and RES feed-in while taking away the base technology. The results of the Case II are compared to Case I in terms of total cost for electricity, installed capacity, share of generation and eventually hour of lost load.

4 Results

In this section the results of the two cases are outlined and compared in the latter. The effects of different levels of CRM are analyzed on the basis of total cost for electricity, share of installed capacity and system adequacy. An overview of the results in the two cases is given in Table 3.

4.1 Case I: Optimal level of payment

The reference case introduces a CRM for each technology that is sufficient to cover the missing revenues due to the price cap. According to the reasoning in Section the level of CRM per technology is set to 2.25635 (€/MW)/h. Expressed as an annual payment, this results in annual steady revenue stream of 19 766 (€/MW)/a for each generator. As expected, the result of the LP equals to optimal case derived from the MCP. Consequently, no load shed applies and all technologies can cover their costs. Consequently, the base technology is replaced by the mid load technology to cope with the phase out. Fig. 5 shows the resulting generation schedule resulting from the LP presented next to the capped price profile.

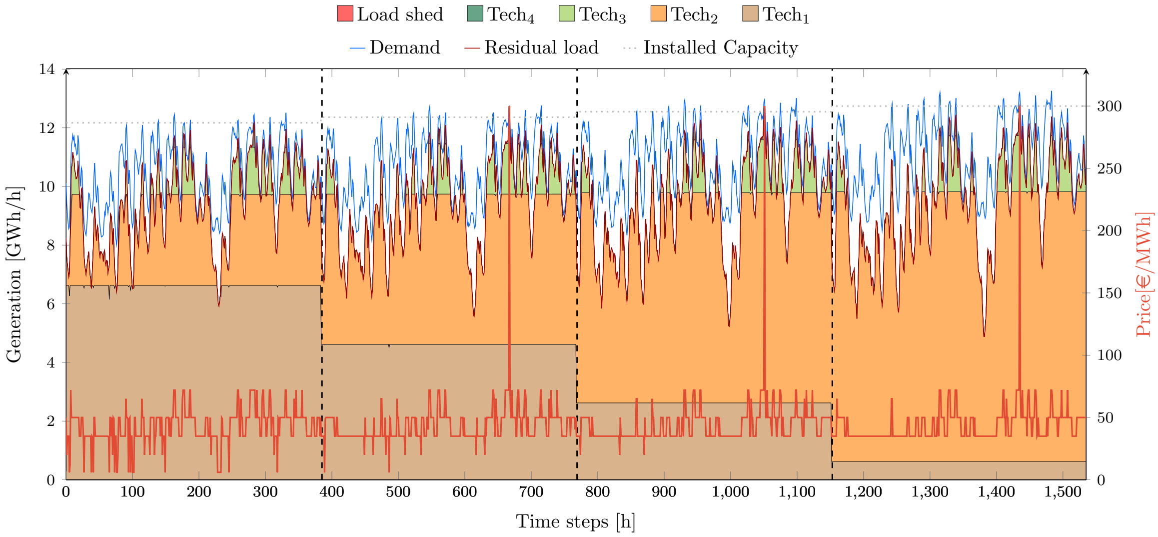

Figure 5: Generation schedule showing the stepwise phase out of the base technology

Assuming that the cost for the CRM is forwarded to the final consumers, their total costs for electricity sum up to 527.87M€ for the last 3 periods. Hereby, 93.82% of the payments origin from selling at electricity prices and 6.18% from the capacity remuneration. More detailed, Fig. 6 reveals the importance of payments from CRM for each individual technology. The share of revenues that originate from the CRM is the highest for the high peak technology. Over the four time periods the required share of CRM stays in the same range and is thus not affected by the changing market conditions.

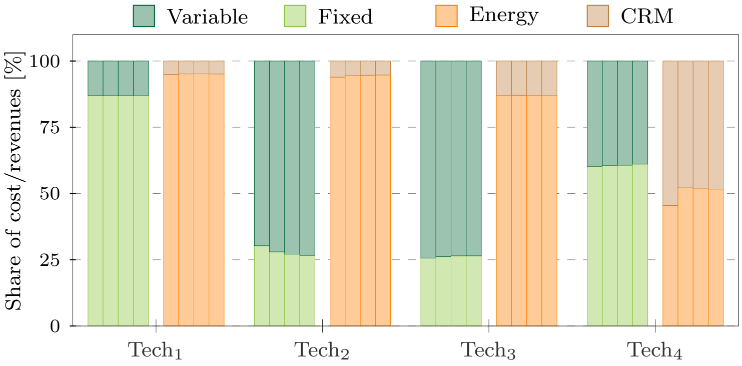

Figure 6: Share of revenues and costs per time period and technology

4.2 Case II: Increased payment for mid load technologies

The second case investigates an unequal level of payment from the CRM. In particular the level for the mid-load technology is increased. While all technologies receive 2.25635 (€/MW)/h as in the reference case, Tech$_2$ receives a higher revenue of 2.6 (€/MW)/h (+15%) or 22 776 (€/MW)/a. Other than in Case I, Tech$_2$ now ends up with an increased profit. The profits of all other technologies stay unchanged.

Compared to Case I, the installed capacity varies for the technologies 2 and 3. The increased level of payment for technology 2 gives a competitive edge and partly replaces parts of technology 3. As a consequence the demand is covered differently. The total generation of technology 3 is reduced and replaced by 2 and 4. Figure 7 depicts the installed capacity and generation in Case II with respect to Case I.

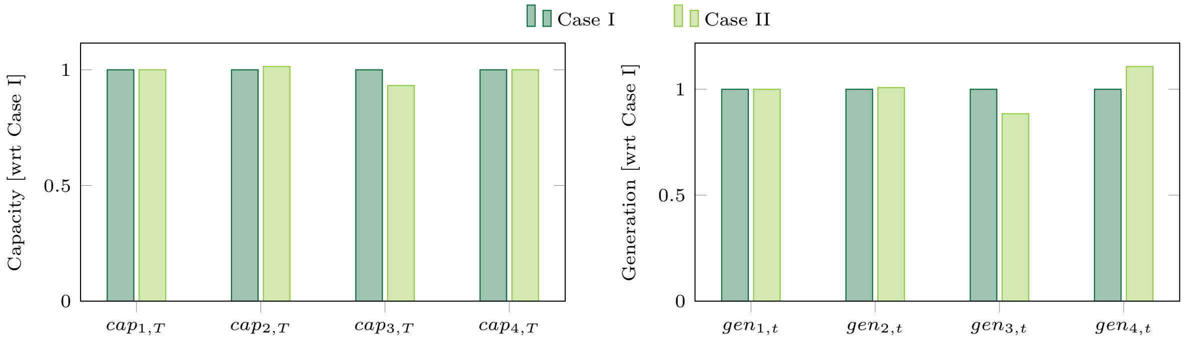

Figure 7: Comparison of Case Results

Due to the changing generation mix and increased capacity remuneration mechanisms, the total costs for electricity increase to 532.37 M€. It is remarkable that although the increased CRM load shedding occurs at few hours of the model. It represents a share of 0.01% of the total demand (see Table 3). These hours are taken into account at an electricity price equal to the market cap (3 000€/MWh).

Table 3: Comparison of Case Results for the last three periods

Case	Total Cost for Society *[M€]*	Load shed *[%]*	$cap_{1,T}$ $\sum gen_{1,t}$ Profit$_1$	$cap_{2,T}$ $\sum gen_{2,t}$ Profit$_2$	$cap_{3,T}$ $\sum gen_{3,t}$ Profit$_3$	$cap_{4,T}$ $\sum gen_{4,t}$ Profit$_4$	*[GW]* *[GWh]* *[M€]*
I	527.87	0.00	0.62 3019.25 1.61	9.20 7222.55 0.00	1.91 528.71 0.00	1.01 28.02 0.00	
II	532.37	0.01	0.62 3019.32 1.61	9.33 7279.94 2.86	1.78 467.44 0.00	1.01 31.29 0.00	

5 Conclusions

The case study in this paper researches the effects of changing market conditions in the electricity market. In particular the effect of very high growth rates of RES combined with an enforced nuclear phase out at the same time.

The applied model shows the reaction of the power generators to the changed market environment. Especially, the effect of the presence of an additional revenue stream originating from a capacity remuneration mechanism is of interest. A fixed payment per technology for the available installed capacity is applied.

In the case study the model is calculated for a simplified generation mix starting from an existing portfolio, i.e. brownfield approach. Each power generator decides on its on generation schedules as well as to increase or decrease its capacity. Hereby, the decision is based on the revenues from selling electricity and the revenues from the capacity remuneration mechanism.

The comparison of the two cases shows that the dependence of profitability for each technology varies. While base technologies only cover a small share, high peak technologies rely more on the revenue streams from a CRM in a market with insufficient prices for selling electricity. Unequal levels of CRM directly influence the installed capacity. This can be understood as market distortion or as direct influence of the policy maker. However, it might also lead to non-optimal generation mixes and eventually load shedding.

Further development of the model includes the modeling of a system operator's behavior. This includes the optimal trade off in between the needed demand to ensure an adequate quality of power supply and additional costs for the scarce needed capacity. Moreover, the estimation of the level of CRM will be implemented endogenous. Finally, the price-elastic demand side, i.e. demand response must be modeled to cover future developments of the power system.

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