DIMENSION – A Dispatch and Investment Model for European Electricity Markets

EWI Working Paper No. 11/03

www.ewi.uni-koeln.de

Institute of Energy Economics
At the University of Cologne (EWI)

Alte Wagenfabrik
Vogelsanger Str. 321
50827 Köln

Tel.: +49 (0) 221 277 29-0
Fax: +49 (0) 221 277 29-400
www.ewi.uni-koeln.de

AUTHOR

Jan Richter

DIMENSION - A Dispatch and Investment Model for European Electricity Markets

Jan Richter*

Abstract: A linear energy system model is presented which optimises the future development of electricity generation capacities and their dispatch in Europe. Besides conventional power plants, combined heat and power plants and power storages, the model considers technologies that support the future high feed in of renewable energies. These technologies include demand side management processes and virtual power storages consisting of electric vehicles.

Keywords: Energy system model, European electricity markets, combined heat and power, demand side management, battery electric vehicles

JEL classification: C61, Q40, Q41, Q47

ISSN: 1862–3808

1 Introduction

European electricity markets have experienced a structural shift since liberalisation by EU Directive in 1996. Well-established supply structures with vertically integrated firms were broken up and replaced by wholesale and retail markets. In most countries, competitive market structures succeeded monopolies.

*Institute of Energy Economics, University of Cologne, Vogelsanger Strasse 321, 50827 Cologne, Germany. E-Mail: jan.richter@uni-koeln.de. I would like to thank Dietmar Lindenberger, Christian Growitsch and Raimund Malischek for their helpful comments and suggestions.

Furthermore, the EU aims to reach climate protection goals according to the Kyoto Protocol of 1997 via an EU-wide emission trading scheme curbing CO_2 emissions. Additionally, each national state implements different support schemes for renewable energies to increase the share of renewable energy in domestic electricity production.[1] A high share of renewable energies, in turn, results in higher fluctuation and less predictability of electricity generation, which increases the demand for balancing power while decreasing full-load hours of conventional power plants. Potentially critical is a lack of investment in capacity that provides security of supply following from that. Hence, and to smooth out supply by renewable energies, compensatory measures such as new storage technologies, demand side management or decentralised micro-CHP plants complementing decentralised renewable energy capacity must be examined.

In short, the complexity of electricity markets in Europe is increasing, leading to new challenges for decision makers. Energy system models are helpful tools for simulating these complex interdependencies. The Institute for Energy Economics at the University of Cologne (EWI) has developed linear simulation models of European electricity markets for many years to help decision makers in business and politics. These models usually minimise long-term or short-term costs of electricity generation subject to various constraints. Typical constraints are meeting inelastic, exogenous demand, achieving a certain mix of production capacity (for example with respect to renewable energies), or providing a specified level of security of supply.

One family of models at EWI simulates long-term developments on markets, specifically investments in power plants, electricity storage and other physical assets of the electricity sector. The results can be interpreted as a solution to the cost-minimization problems (subject to certain restrictions) of social planners. The short-term result, i.e. for existing production and infrastructure capacities, is equivalent to an allocation arising on markets with perfect competition. In the long run, however, this does not have to be the case as the model can invest in technologies that are not profitable at marginal cost prices.

[1] See Fürsch et al. (2010) for a comprehensive overview of different support schemes throughout Europe.

The following provides a non-exhaustive overview of models developed at EWI in the past 15 years. The first electricity market investment model was developed by Hoster (1996) to examine the impact of a single European market on the German electricity industry. In this model, the conventional power plant mix of Germany and (partly aggregated) neighbouring countries was simulated. Starrmann (2001) presents an investment model that extended Hoster's with a heat market, making it possible to model investment decisions in combined heat and power plants (CHP) as well. The model spanned the entire UCTE regions in varying detail. Another expanded version can be found in Bartels and Seeliger (2005).

The models mentioned above are all characterised by a strongly simplified dispatch simulation: There are only 12 different load levels given, three per season in a year. Bartels (2009) has developed a model called DIME where dispatch simulation improved significantly. A total of 288 load levels can be considered in the simulation. This is a decisive improvement especially when modelling increased wind power production, as time series of wind power input inhibit greater variation than others, for example, grid load. These variations cannot be adequately represented by 12 load levels. Moreover, the model is now used to represent 12 EU countries.

DIME has been used in several recent research and consulting projects by EWI. These include an energy policy analysis for the German Government (Schlesinger et al., 2010; Nagl et al., 2011), a study on integrating renewable energy sources for the German Energy Agency (DENA) (German Energy Agency, 2010; Paulus and Borggrefe, 2010), a technical report on the future potential of electric mobility for the German Association of Energy and Water Industries (BDEW) (Richter and Lindenberger, 2010; Richter, 2010) as well as a technical report on the deployment of RES and its impact on the conventional power market (Fürsch et al., 2010).

DIMENSION is being developed to consolidate different simulations of the past projects mentioned above. Specifically, it is enhanced by a module to include demand side management (German Energy Agency, 2010; Paulus and Borggrefe, 2010) and another module to simulate the dispatch of battery electric vehicles (Richter and Lindenberger, 2010; Richter, 2010). Additionally, the dispatch decision has been refined even further. Any number of different load levels up to 8,760 hours per year can now be considered. Wind power input is based on current data provided by EUROWIND. Furthermore, endogenous investment in net transfer capacity between and within countries is now included.

Therefore, the model provides a basis to access fundamental questions of the coming years: How does the electricity production mix change given increased wind power input? What roles do conventional power plants play in the future? How can the several options to integrate renewable energies, such as power storages, demand side management, electric vehicles or decentralised electricity production be combined optimally?

The remainder is structured as follows. Section 2.1 provides some basic definitions. In section 2.2 and 2.3 the basic model equations are presented. Section 2.4-2.6 introduces three modules incorporated in the model: Combined heat and power plants, demand side management and electric vehicle virtual power storages.

2 The Model

In the paper at hand I focus on the model's basic mathematical structure – some details are left out, and the paper does not deal with any kind of data preparation at all.

The model is formulated as a *directed graph* consisting of a set V of *vertices* and a set $E \subset V \times V$ of *edges*. The set of vertices can be subdivided into sources and sinks, where power plants are modelled as sources and demand regions as sinks, for example. In the following, parameters and variables are indicated by lower-case letters, where variables are printed in bold. An electricity flow $\boldsymbol{f}$ between vertices is allowed if these vertices are connected by an edge. I write $a \sim b$, if $(a, b) \in E$ and define for each b the set of *suppliers* by $S(b) := \{a \in E | a \sim b\}$ and the set of *consumers* by $C(b) := \{a \in E | b \sim a\}$.

Each edge has a *capacity* $\boldsymbol{c} : E \to \mathbb{R}_+$ which bounds the flow $\boldsymbol{f}$ between vertices. Moreover, $\alpha : E \to [0, 1]$ denotes an efficiency factor which models electricity losses when an edge is crossed.

The model's *time structure* is represented by a set $T \subset \mathbb{N}$ of points in time. This time structure is flexible and the user can customize it, which means any year until 2050 can be simulated in almost any resolution. Most of the parameters depend on the time structure, but throughout the paper this dependence is omitted.

Example 1. Consider a set P of power plant technologies and that there exists only one market b. Then $V = P \cup \{b\}$ and $a \sim b$ if $a \in P$ is a technology that may produce for market b. The installed capacity of a in b is given by $\boldsymbol{c}(a, b)$. The power plant's own consumption of electricity may be modeled via $\alpha(a, b)$.

2.1 Balance of Demand and Supply

Let $M \subset V$ denote the set of markets demanding electricity. The model's balancing equation is given by

$$\sum_{a:a\in S(b)} \alpha(a,b)\boldsymbol{f}(t,a,b) - \sum_{a:a\in C(b)} \boldsymbol{f}(t,b,a) = d(t,y) \qquad \forall b \in M. \tag{1}$$

In every vertice the difference of inflows and outflows equals demand d, where inflows are weighted with the transportation efficiency α. Note that a can denote a market or a technology. If a is a market, then $\boldsymbol{f}(t, a, b)$ denotes the power transfer from a to b. If a is a power plant technology, then $\boldsymbol{f}(t, a, b)$ denotes the gross electricity production for market b by technology a. See figure 2.1 for an exemplary illustration.

2.2 Capacity Restrictions and Investment

As mentioned above, the flow $\boldsymbol{f}(t, a, b)$ along an edge (a, b) is bounded above by its capacity $\boldsymbol{c}(t, a, b)$. Existing capacity is time-dependent, since commissioning and decommissioning of capacities is allowed. Moreover, let $\beta : E \to [0, 1]$ denote the time-dependent availability of capacity.[2] The capacity restriction is then given by

[2]Consider for example a photovoltaic power plant which can not produce capacity after sunset.

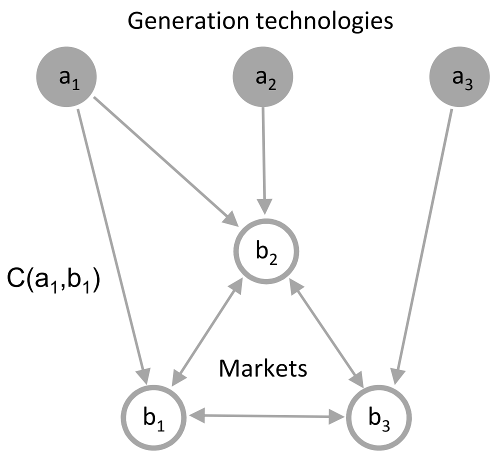

Figure 1: The vertices a_1, a_2, a_3 represent generation technologies, whereas b_1, b_2, b_3 represent markets. The arrows indicate possible flows of electricity and their direction.

$$\boldsymbol{f}(t, a, b) \leq \beta(t, a, b)\boldsymbol{c}(t, a, b). \tag{2}$$

If a and b are markets, then $\boldsymbol{c}(t, a, b)$ denotes the net transfer capacity (NTC) between these markets.

The next equation describes the development of capacity over time. The expression $\Delta\boldsymbol{c}$ equals the net change of installed capacity. This is the sum of capacity investments and capacity decommissioning, where decommissioned capacity in turn is the sum of capacity that is worn out due to lifetime restrictions and of capacity that is decommissioned endogenously for economic reasons. Further restrictions are imposed so that capacity extensions can be bounded or supressed for specific elements (a, b).[3] These restrictions are self-explanatory and thus omitted here.

$$\boldsymbol{c}(t+1, a, b) = \boldsymbol{c}(t, a, b) + \Delta\boldsymbol{c}(t, a, b). \tag{3}$$

[3]For example nuclear power plants in Germany.

In addition to the overall capacity restriction (2) the gradients of power plants are modelled. Since the model is linear, the gradients are linearly approximated. First, a minimum load condition is imposed. The minimum load share of a supplier is given by $\gamma : V \to [0,1]$. Let $\boldsymbol{c^{op}}$ denote the absolute amount of capacity that is in operation. Then:

$$\gamma(a)\boldsymbol{c^{op}}(t,a,b) \leq \boldsymbol{f}(t,a,b) \leq \boldsymbol{c^{op}}(t,a,b) \leq \beta(t,a,b)\boldsymbol{c}(t,a,b) \tag{4}$$

The flow $\boldsymbol{f}$ is allowed to change in the interval $[\gamma\boldsymbol{c^{op}}, \boldsymbol{c^{op}}]$ without restrictions regarding the mechanical inertia of a power plant. This approximates that if a power plant is in part load, it will be able to increase its output relatively quickly. Contrarily, it takes time for some technologies to start producing.

Second, the change of $\boldsymbol{c^{op}}$ is restricted – the evolution of $\boldsymbol{c^{op}}$ is given by

$$\boldsymbol{c^{op}}(t+1,a,b) = \boldsymbol{c^{op}}(t,a,b) + \Delta\boldsymbol{c^{op}}(t,a,b). \tag{5}$$

Let $\delta : V \to \mathbb{R}$ denote the reciprocal of the startup time of a power plant.[4] The variable $\Delta\boldsymbol{c^{op}}$ is then restricted by

$$\Delta\boldsymbol{c^{op}}(t,a,b) \leq \delta(a)(\boldsymbol{c}(t,a,b) - \boldsymbol{c^{op}}(t,a,b)). \tag{6}$$

The difference $\boldsymbol{c} - \boldsymbol{c^{op}}$ is the total amount of capacity that is not in operation mode which can partly be activated when moving from t to $t+1$.

2.3 Power Storages

Let $a \in V$ be a storage and $b \in V$ be a market. As for power plants, the installed capacity of power storages is by $\boldsymbol{c}(t,a,b)$ and measured in watts (W). To calculate the storage's volume measured in Wh, which is denoted by $\boldsymbol{v}(t,a,b)$, a *discharging time* $\theta : V \to \mathbb{R}_+$ is used which equals the time it takes to empty a full storage. This implies that a constant ratio of a storage's volume and its generation capacity is assumed. Thus, this ratio is treated as a characteristic of a specific storage technology. This gives:

[4] In fact, the start up time of a power plant depends on the plant's idle time and thus is not constant. I use a mean value.

$$\boldsymbol{v}(t,a,b) \leq \theta(a)\boldsymbol{c}(t,a,b). \tag{7}$$

Regarding compressor capacity, i.e. the injection rate, it is assumed that this is proportional to the generation capacity as well. Let ϵ denote the ratio of the injection and withdrawal rate. The maximal storage injection $\boldsymbol{f}(t,b,a)$ is then bounded according to equation (8):

$$\boldsymbol{f}(t,b,a) \leq \epsilon(a)\boldsymbol{c}(t,a,b), \tag{8}$$

Equation 9 finally describes the evolution of a storage's volume over time. Note that, in particular, this equation would become more complex if the dependency on the time structure T was taken into account.

$$\boldsymbol{v}(t+1,a,b) = \boldsymbol{v}(t,a,b) + \alpha(a,b)\boldsymbol{f}(t,b,a) - \boldsymbol{f}(t,a,b). \tag{9}$$

Example 2. If $a \in V$ is a power storage and $b \in V$ is a market so that $a \sim b$, then $b \sim a$ holds, too. The power storage is then considered as a consumer of b. If $\boldsymbol{c}(t,a,b)$ $= 100\,\text{MW}$ and if it takes, say, five hours to empty the storage, then the storage volume is given by $5\,\text{h} \times\ 100\,\text{MW} = 500\,\text{MWh}$. If $\epsilon(a) = 0.5$, then compressor capacity equals 50 MW.

2.4 Combined Heat and Power Plants

The module presented here was introduced by Starrmann (2001) and developed further by Bartels (2009). Cogeneration plants generate electricity and usable heat at the same time. This combined process reduces the amount of primary energy used compared to the situation where both products are generated separately, i.e. power plants and heating plants. If the model's network structure covered only vertices demanding electricity, the cost-saving effects of cogeneration would be disregarded, and investments in cogeneration plants would be underestimated. Thus, an additional set $H \subset V$ of vertices is introduced which represents markets for district heating. It is assumed that every $c \in H$ is connected with exactly one electricity market $b \in V$, so that $b \sim c$ for exactly one b. On the other hand, more than one heat market may be connected with b. Let $H(b)$ denote the set of heat markets belonging to b, i.e. $H(b) = \{c \in H | (b, c) \in E\}$. Now, if $a \in V$ is a cogeneration plant so that $a \sim b$, it is claimed that $a \sim c$ for exactly one $c \in H(b)$, which means that a cogeneration plant a may serve a market b for electricity and exactly one market c for heat that is connected with b. I denote this unique c by $h(a, b)$. See figure 2.4 for an exemplary illustration of the network structure.

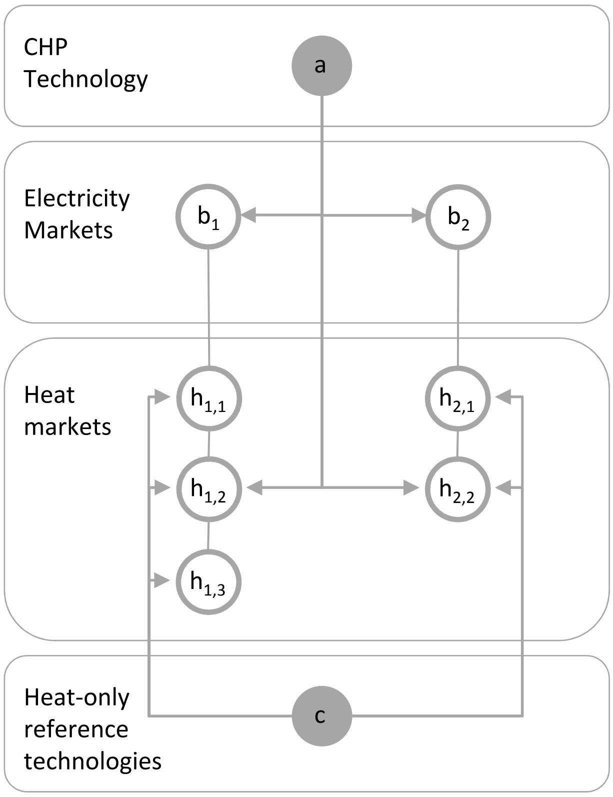

Figure 2: The CHP plant a may serve both electricity markets b_1 and b_2 and exactly one heat market that is connected to each electricity market: In this example we have $h(a, b_1) = h(a, b_2) = h_{2,2}$. CHP plants compete with heat-only plants denoted by c.

An important technical characteristic of a cogeneration plant is the power to heat production ratio. This ratio can be constant or flexible depending on the specific cogeneration technology and it determines the flexibility of the plant. It has a considerable impact on the plant's dispatch. If, for example, electricity demand is low, heat demand is high and a plant has a constant and high power to heat ratio, it will probably be inefficient to serve heat demand by this plant. Instead, a pure heating plant will probably be dispatched. If the plant has flexibility regarding its power to heat ratio, it might decrease electricity production and keep heat production on a constant level.

If $a \in V$ is a cogeneration plant with a fixed power to heat ratio $\rho(a)$ and if b is a market so that $|H(b)| > 0$ holds, the following equation must hold:

$$\boldsymbol{f}(t, a, b) = \rho(a)\boldsymbol{f}(t, a, h(a, b)). \tag{10}$$

That is, for every unit $\boldsymbol{f}(t, a, b)$ of electricity the cogeneration plant must produce $\rho(a)\boldsymbol{f}(t, a, h(a, b))$ units of heat. Note that for $\boldsymbol{f}(t, a, b)$ the capacity restriction (2) holds and thus $\rho(a)\boldsymbol{f}(t, a, h(a, b))$ is bounded appropriately.

If $a \in V$ is a cogeneration plant that has a flexible power to heat ratio the equation above is relaxed:

$$\boldsymbol{f}(t, a, b) \geq \rho(a)\boldsymbol{f}(t, a, h(a, b)). \tag{11}$$

Thus, a cogeneration plant a may generate electricity without generating usable heat, but not the other way round, and $\rho(a)$ may be viewed as the minimum power to heat ratio that is allowed for a. Thus, in a well defined range a flexible cogeneration plant can "trade" one unit of electricity for some units of heat, where the exchange rate does not equal one but is given by the *power loss ratio* $\sigma(a)$. One unit of electricity and $\sigma(a)$ units of heat are then equivalent, which leads to the following capacity restriction:

$$\boldsymbol{f}(t, a, b) + \sigma(a)\boldsymbol{f}(t, a, h(a, b)) \leq \beta(t, a, b)\boldsymbol{c}(t, a, b). \tag{12}$$

Note that if a does not produce usable heat this equation reduces to equation (2).

Example 3. Let b represent a geographic region in some country, and let $H(b) = \{c_1, c_2\}$. For example, c_1 can be seen as a market for district heating and c_2 for process heating in this region. Demand for heat can only be served by heating plants or by cogeneration plants that are located nearby, i.e. located in b, which originally motivated the modelling approach that every heat market is connected with some unique electricity market. A flexible cogeneration plant that is located in b is defined by its electricity generation capacity $\boldsymbol{c}(t, a, b) = 1000\,\text{MW}$. Moreover, let $\rho(c) = 0.66$ and $\sigma(c) = 0.2$. Equations (11) and (12) give that the extreme points of the set of feasible production combinations are *1000 MW electricity/0 MW heat* and *715 MW electricity/1429 MW heat*. The convex hull of these two points and the origin gives the set of feasible production combinations. Figure 2.4 provides a qualitative illustration.

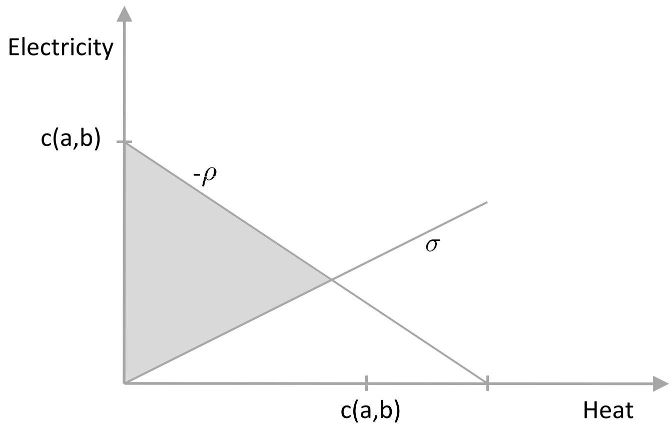

Figure 3: The set of feasible production combinations is grey colored. The parameters σ and ρ define the slope of the boundaries.

2.5 Demand Side Management Processes

The demand side management (DSM) module presented here was developed by EWI and applied by the German Energy Agency (2010) and Paulus and Borggrefe (2010). By a *process* I mean any kind of "action" demanding electricity. A *DSM process* is a process whose demand is price-elastic in the short term. An example of a DSM process in the industry sector is aluminium electrolysis, an example of a domestic DSM process is night storage heating. In the model a DSM process is a process that may deviate from its mean electricity consumption. A specific DSM process is modelled as a vertice $u \in U \subset V$.

In the paper at hand, so far only the supply side of the electricity system was taken into account, whereas the demand side was considered to be inelastic and to be represented by $d(t, b)$, a number that was originally determined top down. In contrast to that, the potential for demand side management was determined by a bottom-up approach in earlier EWI contributions (German Energy Agency, 2010; Paulus and Borggrefe, 2010). Let's assume for the moment that we may access the "set of all *processes*" which I denote by $\tilde{U}$. Then it holds that $U \subset \tilde{U}$. For every $\tilde{a} \in \tilde{U}$, let $d_{\tilde{a}}(t, m)$ denote the average demand of the process $\tilde{a}$. To ensure consistency between the top-down and bottom-up approach, it is required that

$$\sum_{\tilde{a} \in \tilde{U}} d_{\tilde{a}}(t, m) = d(t, b). \tag{13}$$

Let $a \in U$ denote a DSM process and let $d_a(t, m)$ denote its average demand. In order to define the flexibility of a with respect to $d_a(t, b)$ numbers $d_a^-(t, b)$ and $d_a^+(t, b)$ have to be defined so that

$$d_a^-(t, b) \leq d_a(t, b) \leq d_a^+(t, b) \tag{14}$$

holds. These boundaries d_a^- and d_a^+depend on technical characteristics and installed load in every market of each process. See also German Energy Agency (2010) and Paulus and Borggrefe (2010) for an estimation procedure. This gives the potential of DSM from a technical point of view:

$$0 \leq \boldsymbol{c}(t, a, b) \leq d_a(t, b) - d_a^-(t, b), \tag{15}$$

$$0 \leq \boldsymbol{c}(t, b, a) \leq d_a^+(t, b) - d_a(t, b). \tag{16}$$

As for power plants, the capacity restriction (2) and any other equation containing the capacity variable $\boldsymbol{c}$ holds for DSM processes as well. Moreover, if a process is inert, equation (6) can be extended to cover such DSM processes.

In general, DSM processes can be distinguished as shift load processes characterised by a constant accumulated electricity consumption in a specific period, and shed load processes which can reduce the accumulated consumption of electricity. For a shift load DSM process further restrictions have to be imposed. The next equation ensures that the consumption of electricity is constant during the time period T under consideration:

$$\sum_{t \in T} \alpha(b,a)\boldsymbol{f}(t,b,a) - \boldsymbol{f}(t,a,b) = 0. \tag{17}$$

The factor α can be used to model losses that arise from load shifting. For most of the processes, equation (17) is formulated for several subsets of T. For example, washing machines have to catch up shifted energy in 24 hours.

Example 4. Consider the production process of aluminium where an electrolysis is conducted. Let's assume there is an installed load of 1500 MW in Germany. The accumulated electric power the electrolysis actually demands is assumed to be constant and to equal 1100 MW during normal operation. This demand may be increased by 5 % or reduced by 10 %. The technical potential for load increase is then given by

$$d_a^+(t,b) - d_a(t,b) = 1.05 \cdot 1100 - 1100 = 55, \tag{18}$$

the technical potential for laod decrease by

$$d_a(t,b) - d_a^-(t,b) = 1.1 \cdot 1100 - 1100 = 110. \tag{19}$$

This leads to $c(t,a,b) \leq 55$ and $c(t,b,a) \leq 110$. Moreover, we assume that the process has a constant demand during a period of 48 hours (cp. equation (17) for an appropriate subset of T).

2.6 Electric Vehicles Virtual Power Storages

Electric vehicles are treated in a similar way as storages and demand side management processes. The module presented here was developed and evaluated by Richter and Lindenberger (2010) and Richter (2010).

In the model a battery electric vehicle (BEV) is characterised by its battery capacity in terms of Wh, discharging time θ and its ratio of injection and withdrawal rate ϵ.[5] The storage volume bound (7) holds true for electric vehicles as well. In addition to that, the storage equation (9) is extended by an outflow $\tau(t,w)$, which is due to the fact that electric vehicles demand electricity for

[5] These rates rely on assumptions regarding the technical properties of the battery and the recharging station.

driving purposes:

$$\boldsymbol{v}(t+1,a,b) = \boldsymbol{v}(t,a,b) + \alpha(a,b)\boldsymbol{f}(t,b,a) - \boldsymbol{f}(t,a,b) - \tau(t,a) \tag{20}$$

This outflow is estimated based on the vehicles' driving profiles (Richter and Lindenberger, 2010).

In this context, the parameter β describes the share of electric vehicles that is connected to the grid at a specific point in time. It is assumed that electric vehicles may feed electricity back to the grid, so that equation (2) holds for electric vehicles as well. The charging speed of electric cars is bounded by equation (8).

A new element that arises when modelling electric vehicles stems from the fact that the storage volume connected to the grid depends on time. The expression $\theta(a)\boldsymbol{c}(t,a,b)$ equals the overall storage volume, and the variable $\boldsymbol{v}(t,a,b)$ equals the energy stored in this volume in t. Only a share of $\beta(t,a,b)$ of the overall storage volume is connected to the grid.

Now, a difficulty arises because thus far it is left open which share of $\boldsymbol{v}(t,a,b)$ is stored in $\theta(a)\boldsymbol{c}(t,w,b)$. However, I chose the simplest approach and assume that the share of energy stored in batteries that are connected to the grid equals $\beta(t,a,b)$. This means that at any point t in time an empty storage volume that equals $\beta(t,a,b)(\boldsymbol{c}(t,a,b) - \boldsymbol{v}(t,a,b))$ is ready to be charged. Thus, two additional restrictions have to be imposed:

$$0 \leq \boldsymbol{f}(t,b,a) \leq \beta(t,a,b)(\boldsymbol{c}(t,a,b) - \boldsymbol{v}(t,a,b)) \tag{21}$$

and

$$0 \leq \boldsymbol{f}(t,a,b) \leq \beta(t,a,b)\boldsymbol{v}(t,a,b). \tag{22}$$

The flexibility that is left after imposing these restrictions is used by the model to dispatch electric vehicles like a storage.

Example 5. Let's consider one type of electric vehicle. We assume that there are 1,000,000 EVs and each battery has a storage volume that equals 30 kWh. The discharging and recharging times coincide ($\epsilon(a) = 1$) and equal 3 hours ($\theta(a) = 3$). The accumulated storage has a volume of 30 GWh. The capacity of electricity generation is $\boldsymbol{c}(t,a,b) = 10\,\text{GW}$. If at t one third of all vehicles is connected to the grid, and if $\boldsymbol{v}(t,a,b) = 15\,\text{GWh}$, then the empty storage volume connected to the grid (and thus can be recharged) amounts to $1/3 \cdot (30 - 15) = 5\,\text{GWh}$.

2.7 Objective Function

The objective function is the discounted sum of some variables introduced earlier, weighted with specific costs. The discount factor is neglected here to keep notation simple. The classes of variables considered in the objective function are $\boldsymbol{f}$ (the flow between vertices), $\boldsymbol{c}$ (the capacity between vertices), $\Delta\boldsymbol{c}$ (the net change of installed capacity) and $\Delta\boldsymbol{c}^{\boldsymbol{op}}$ (the net change of capacity that is ready to operate).

The flow $\boldsymbol{f}(t,a,b)$ between vertices (a,b) is weighted with its variable costs which I denote by $\boldsymbol{x_f}(t,a,b)$. The sum over T and E is denoted by $\boldsymbol{x}_f$:

$$\boldsymbol{x_f} = \sum_{T\times E} \boldsymbol{x_f}(t,a,b).$$

Example 6. If $a \in V$ is a power plant and $b \in V$ is a market, the variable $\boldsymbol{f}(t,a,b)$ denotes the electricity generation by a in b at t. The variable costs $\boldsymbol{x_f}(t,a,b)$ may then be modelled as the sum of fuel costs and other variable costs.

Example 7. Let $a \in V$ denote a load-shedding DSM process and $b \in V$ a market. Then the variable $\boldsymbol{f}(t,a,b)$ denotes the load that is shedded in t, and $\boldsymbol{x_f}(t,a,b)$ denotes the value of lost load.

For each $(a,b) \in E$ the capacity $\boldsymbol{c}(a,b)$ is treated as an asset. Its annuity is calculated with respect to the asset's specific investment costs, depreciation period and rate of return. This gives the annual fixed costs for $\boldsymbol{c}(t,a,b)$. The sum over all the years considered and over all $(a,b) \in E$ gives the accumulated investment costs and is denoted by $\boldsymbol{x}_{\Delta c}$.

The fixed operation and maintenance costs are obtained by multiplying the existing capacity $\boldsymbol{c}(t,a,b)$ with some specific cost factor which includes labour costs, for example. I denote the accumulated FOM costs by $\boldsymbol{x}_c$.

Example 8. Let $a \in V$ be a 1,000 MW power plant and $b \in V$ be a market. If the specific investment costs of (a,b) equal 800 €/kW, the depreciation period of (a,b) equals 20 years, and if we assume a rate of return of 0.1, the annuity is given by

$$1,000\,\text{MW} \cdot 800\,€/\text{kW} \cdot \frac{(1+0.1)^{20}\cdot 0.1}{(1+0.1)^{20}-1} = 93,967.7\,€.$$

The model takes into account that it is costly to increase the electricity production of a power plant due to increased equipment attrition and increased fuel consumption. The weighted sum of all $\Delta \boldsymbol{c}^{\boldsymbol{op}}(t,a,b)$ is denoted by $\boldsymbol{x}^{\boldsymbol{op}}_{\Delta \boldsymbol{c}}$.

Summing up all cost components gives the objective function, where $\boldsymbol{x}$ denotes the accumulated discounted costs (as mentioned earlier, the discount factor is neglected for the sake of a simple notation).

$$x = \underbrace{\boldsymbol{x}_f}_{\text{variable costs}} + \underbrace{\boldsymbol{x}_{\Delta c}}_{\text{invest costs}} + \underbrace{\boldsymbol{x}_c}_{\text{FOM costs}} + \underbrace{\boldsymbol{x}_{c^{op}}}_{\text{ramp up costs}} . \tag{23}$$

A solution is obtained by minimizing $\boldsymbol{x}$. The model is implemented in GAMS 23.3, the solver package is CPLEX 12.

3 Summary and Outlook

The paper at hand presents a linear energy system model for simulating European electricity markets which emphasises future investment in conventional generation capacity. Earlier modelling approaches developed at EWI were consolidated and refined. New developments focus on future requirements concerning electricity markets characterised by a high feed in of renewable energies: Increased flexibility in electricity generation, increased elasticity of electricity demand and new options for storing electricity.

In the model presented renewable energie sources (RES) are treated exogenously, which means that the share as well as the mix of RES is not a model result. To evaluate the interdependency of RES feed in and flexibility options an endogenous treatment of RES would be preferable. The model, as described, is fully compatible with endogenous RES. Moreover, the development of a balancing power market module that captures the connection to the energy market would improve the simulation of the power plants' dispatch and thus the simulation of capacity investments.[6] These two enhancements of the model will be addressed by future research. Moreover, applications of the model will be provided.

[6]The model DIME developed by Bartels (2009) provides a simplified balancing power market.

References

Bartels, M., 2009. Cost Efficient Expansion of District Heat Networks in Germany. Oldenbourg Industrieverlag.

Bartels, M., Seeliger, A., 2005. Interdependenzen zwischen Elektrizitätserzeugung und Erdgasversorgung unter Berücksichtigung eines europäischen CO2-Zertifikatehandels (in German). In: Tagungsband der 4. Internationalen Energiewirtschaftstagung (IEWT).

Fürsch, M., Golling, C., Nicolosi, M., Wissen, R., Lindenberger, D., 2010. European RES-E Policy Analysis – A Model-based Analysis of RES-E Deployment and its Impact on the Conventional Power Market. Tech. rep., Energiewirtschafltiches Institut an der Universität zu Köln (EWI).

German Energy Agency, 2010. dena Grid Study II – Integration of Renewable Energie Sources into the German Power Supply System in the 2015-2020 Period with Outlook to 2025.
URL http://www.dena.de/fileadmin/user_upload/Download/Dokumente/Studien___Umfragen/dena_Grid_Study_II_-_final_report.pdf

Hoster, F., 1996. Auswirkungen des europäischen Binnenmarktes für Energie auf die deutsche Elektrizitätswirtschaft (in German). R. Oldenbourg Verlag.

Nagl, S., Fürsch, M., Paulus, M., Richter, J., Trüby, J., Lindenberger, D., 2011. Energy Policy Scenarios to Reach Challenging Climate Protection Targets in the German Electricity Sector until 2050. Utilities Policy, in press.

Paulus, M., Borggrefe, F., 2010. The Potential of Demand-Side Management in Energy-Intensive Industries for Electricity Markets in Germany. Applied Energy 88, 432–441.

Richter, J., 2010. Charging Electric Cars under Real-Time Electricity Prices as an Action of Demand Side Management. In: Proceedings of the 11th IAEE European Conference, Vilnius.

Richter, J., Lindenberger, D., 2010. Potenziale der Elektromobilität bis 2050 – eine szenarienbasierte Analyse der Wirtschaftlichkeit, Umweltauswirkungen und Systemintegration (in German). Tech. rep., Energiewirtschaftliches Institut an der Universität zu Köln.

Schlesinger, M., Hofer, P., Kemmler, A., Kirchner, A., Strassburg, S., Lindenberger, D., Fürsch, M., Nagl, S., Paulus, M., Richter, J., Trüby, J., 2010. Energieszenarien für ein Energiekonzept der Bundesregierung (in German). Tech. rep., Prognos AG, Energiewirtschaftliches Institut an der Universität zu Köln and GWS mBh.

Starrmann, F., 2001. Entwicklung der Kraft-Wärme-Kopplung in liberalisierten Elektrizitätsmärkten (in German). Oldenbourg Industrieverlag.

ABOUT EWI

EWI is a so called An-Institute annexed to the University of Cologne. The character of such an institute is determined by a complete freedom of research and teaching and it is solely bound to scientific principles. The EWI is supported by the University of Cologne as well as by a benefactors society whose members are of more than forty organizations, federations and companies. The EWI receives financial means and material support on the part of various sides, among others from the German Federal State North Rhine-Westphalia, from the University of Cologne as well as – with less than half of the budget – from the energy companies E.ON and RWE. These funds are granted to the institute EWI for the period from 2009 to 2013 without any further stipulations. Additional funds are generated through research projects and expert reports. The support by E.ON, RWE and the state of North Rhine-Westphalia, which for a start has been fixed for the period of five years, amounts to twelve Million Euros and was arranged on 11th September, 2008 in a framework agreement with the University of Cologne and the benefactors society. In this agreement, the secured independence and the scientific autonomy of the institute plays a crucial part. The agreement guarantees the primacy of the public authorities and in particular of the scientists active at the EWI, regarding the disposition of funds. This special promotion serves the purpose of increasing scientific quality as well as enhancing internationalization of the institute. The funding by the state of North Rhine-Westphalia, E.ON and RWE is being conducted in an entirely transparent manner.