A Simulation-based Analysis of Transition Pathways for the Dutch Electricity System

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Abstract

Recent developments constitute a backdrop of change for the Dutch electricity system. Institutional change driven by liberalization, changing economical competitiveness of the dominant fuels, new technologies, and changing end-user preferences regarding electricity supply are some examples of these developments. In order to analyze the conjoint impact of such developments on the internal dynamics of the electricity system (grid-based and distributed generation), a simulation model is developed. The simulation experiments with the model indicate the continuation of fossil fuel dominance as the energy source, and a shift from natural gas to coal seems likely in the base case. In other cases, it is seen that a transition away from carbon-intensive mode requires significant regulatory intervention, since technological developments and 'greening' end-users fail to trigger a system-wide transition. Moreover, it is observed that policies for carbon abatement and renewable generation support are intertwined, and may lead to unintended shifts of abatement costs to end-users.

1. Introduction

Large-scale socio-technical systems, such as electricity supply, are characteristically hard to change. This is primarily due to the past commitments made (social, physical and economical), intrinsic delays, and strong balancing feedbacks in these systems. The Dutch electricity system is a typical example of such hard-to-change systems. However, when the current developments are analyzed, it is seen that there is a transition-favoring climate for this system.

First of all, the Dutch system has been going through a significant institutional transformation from a vertically integrated design to a liberalized electricity system in accordance with the European Union electricity directives since 1998 (van Damme 2005). Briefly, the whole change process resembles a gradual shift from a system operated by a central operator managing the system for *cost minimization*, to a system of independent actors operating their infrastructure for *individual profit maximization*. This shift will influence the way the infrastructure will evolve over time (de Vries 2004). However, due to long delays typical to large-scale socio-technical systems, the impacts of this transformation on the infrastructure's evolution will be more apparent in the following years.

The second development is about capacity investment cycles. A detailed survey of the generator park reveals the fact that an important portion (around 20%) of conventional plants commissioned during 1970's (Rödel 2008). These plants are already beyond their estimated lifetimes, and are expected to be decommissioned during the following decade. If smaller-scale cogeneration plants and coal-based generators close to the end of their lifetimes are also considered, the portion of the generation park to be decommissioned becomes even larger. If this capacity loss is to be compensated by new capacity, an important change in the generation portfolio may be possible, also considering the aforementioned management mentality shift. On the other hand, if the loss is not compensated, the Dutch demand-supply capacity situation may experience its tightest levels.

Technological developments are also important. These include both developments on the already utilized technologies, as well as novel ones at the brink of commercialization. Notable developments are being achieved, and further expected, in the efficiency and emission performance of coal-based and gas-based combustion technologies (Lako 2004; Rödel 2008). Besides this, there are new technologies and practices recently introduced or about to be introduced. These include carbon capture and storage (CCS) (Smekens 2005; van den Broek, Faaij et al. 2008), fuel cells (Martinus, Blesi et al. 2005), novel biomass gasification and combustion technologies (Caputo, Palumbo et al. 2005), off-shore wind-farms, and micro co-generators (m-CHP) (Pehnt, Cames et al. 2006; Faber, Valente et al. 2008), which may yield important changes in the way electricity supply system is organized and operated.

Changes in the energy markets, especially in the primary fuel markets, are also influential in the evolution of the Dutch electricity system. Natural gas-based generators currently dominate the Dutch system both in terms of generation and active capacity. Due to the price changes during the last 15 years, natural gas lost its economic attractiveness significantly (Figure 1). The shift in the generation is already visible since coal-based generators are getting a bigger share of the base load, while the share of gas-based generation is shrinking. In the long run, this price-related development may also lead to a significant shift in the generation portfolio keeping in mind the upcoming capacity renewal need mentioned above.

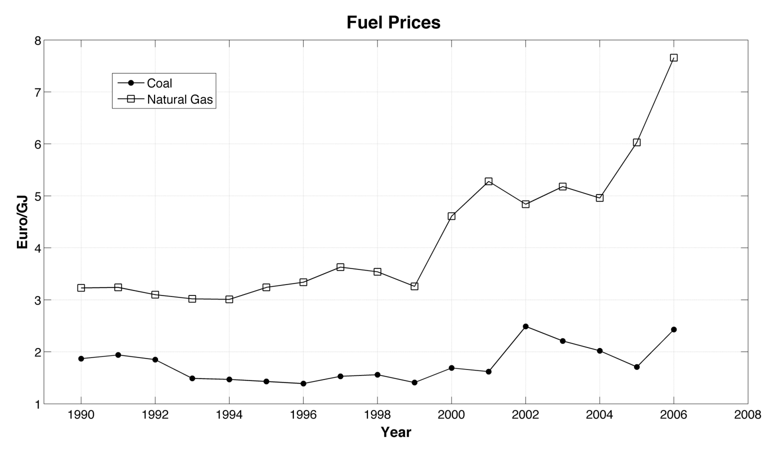

Figure 1. Fuel Prices (Source: CBS Statline (2009))

A change in the social sphere has also been visible in the past decade. At the state level, dedication for a more environmentally friendly, sustainable and secure system is apparent. The reflection of this dedication can be seen in the targets set by the government (e.g. 20% renewable electricity by 2020, Kyoto targets, 6 GW off-shore wind energy capacity). A change along similar lines is also taking place at the end-user level: environmental concerns are on the rise against the economic criteria that can be claimed to dominate end-user behavior in this context up until now. For industrial and commercial users, it’s the increasing value of *environmental friendliness* in the market value of the firm that yields *‘green’* options to be brought on to the table. In short, an increase in the environmental values, whatever underlying driver may be, is apparent. The impact if such a change may be expected to have an influence on the evolution of the electricity system.

It can be seen that the Dutch electricity system is going through an era during which significant changes in multiple dimensions, such as technological, social, infrastructural, regulatory and economic, are taking place. The co-existence of these developments is what makes the current era a climate in which a transition may emerge. However, whether the system will shift to a newly emerging trajectory, or not is not apparent. The development trajectory will be shaped by the internal dynamics of the system under the influence of the aforementioned contextual developments. This dynamic puzzle constitutes the main motivation behind this study, which aims to develop insights about plausible development paths for the Dutch electricity system. However, due to the intrinsic dynamic complexity of the system, this puzzle goes beyond intuition, and the static approaches have very limited to offer. Therefore, a simulation-based analysis is utilized for looking into the dynamics of change in the Dutch electricity supply system.

Following section introduces the simulation model developed for this analysis; namely *ElectTrans*. Introduction focuses mainly on the scope of the model, and the way electricity supply system is conceptualized. Section 3 is devoted to the simulation experiments, which includes the main base case experiment, and four scenario runs. The last section summarizes the experiment outcomes, and discusses future directions.

2. Model Description

This section provides an overview of the model developed for exploring transition trajectories for the Dutch electricity system, i.e. *ElectTrans*. The overview aims to clarify the system boundary, the main assumptions, and the conceptual representation of the system and the system actors that are represented in the model. The model is developed based on the actor-option framework (Yücel 2010) for modeling socio-technical transitions.

ElectTrans is an agent-based model, which explicitly focuses on multiple actor groups within the electricity system (e.g. generation companies, households, industrial users, the state as a regulator, etc.). Besides being represented in an agent-based architecture, the model builds upon the fundamental notions of the system dynamics perspective: the feedback within and among these agents, the delays between the actions and their consequences, and the delays in the perception of these consequences are seen as the major factors that condition the system behavior.

The description of the model is structured around the major aspects of the system; i.e. demand, supply, and regulation. A more detailed documentation of the model can be found elsewhere (Yücel 2010).

a. *End-users and the electricity demand*

A preliminary investigation points to different user categories, which differ in the demand patterns as well as preference structures that drive their decisions. Clustering these heterogeneous user groups in a single category is evaluated to be insufficient for the purposes of this study. Therefore, four groups of end-users are represented in the model, which are industrial users, commercial users, horti-/agricultural users, and households.

It is possible to name two major supply options for all actor groups, i.e. using electricity supplied via central generation, and adoption of distributed generation options[1] for self-generation. In the way it is conceptualized in the model, the primary choice to be given by an end-user is about getting the electricity from central grid, or generating electricity via distributed generation options. There are two grid-based options in the model: gray electricity and green electricity[2]. Various distributed generation options are also available, such as wind turbines and gas engine CHPs. Table 1 provides aggregate list of the supply options, including both grid-based and distributed ones, available in the model, as well as their appropriateness for individual actor groups. Whether an option is appropriate for a particular actor group, or not is determined mainly on the basis of demand-capacity match criteria. If commercially available sizes of an option are close to average end-user demand for an actor group, that option is defined as usable for that actor group.

Table 1. Electricity supply options for end-user groups in ElectTrans

Option Name	Households	Agricultural Users	Commercial Users	Industrial Users
Grid Electricity (Gray)	☑	☑	☑	☑
Grid Electricity (Green)	☑	☑	☑	☑
Micro-CHP	☑	☒	☑	☒
PV Roof	☑	☑	☑	☒
CHP (Gas Engine)	☒	☑	☑	☒
CHP (Gas Turbine)	☒	☑	☑	☑
CHP (CCGT)	☒	☒	☒	☑
Biomass Combustion	☒	☑	☒	☑
Biomass Gasification	☒	☑	☒	☑
Wind Turbine (Inland)	☑	☑	☑	☑
Wind Farm (Inland)	☒	☑	☑	☑
Wind Farm (On Shore)	☒	☒	☒	☑
Wind Farm (Near shore)	☒	☒	☒	☑
Wind Farm (Off-shore)	☒	☒	☒	☑

☑: Option appropriate/usable for the actor type
☒: Option not appropriate/usable for the actor type

The set of diverse options enables capturing alternative transition trajectories (e.g. distributed cogeneration, green supply, etc.) into which the actors may push the system via their choices. Moreover, this wide coverage enables studying the

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[1] The terms 'distributed generation' is used similar to the sense it has been defined by Pepermans *et.al.* (2005). Briefly, a distributed generator is defined to be one that is not dispatchable by the system operator.

[2] Electricity generated from renewable sources such as wind, solar, biomass, etc.

competition among available options, which lacks in most models with a single-technology focus (e.g. diffusion of wind generation).

In the midst of this option variety, it is the decisions of the actor groups that will influence the way system will shape in the long run. These decisions are not just based on cost figures, but they are multi-dimensional decisions where environmental and social issues also play a role. Representation of such a decision process in the model is of primary importance. Although it is not possible to represent the complicated decision process of individuals as it is, it is possible to formulate decision heuristics that provide decisions that resemble the decisions of real actors. Referring to the decision analysis field (Keeney and Raiffa 1993; Keeney and Gregory 2005), in order to formulate such a decision process a *preference structure*, which specifies the relevant importance of the assessment criteria, is used. In the preference structure implemented, the actor groups consider four criteria; *cost of supply*, *price volatility*, *environmental performance*, and *in-group familiarity*. Among these criteria, *environmental performance* refers to direct CO_2 emissions caused per kWh electricity generated by the evaluated options, and *familiarity* refers to the diffusion of the option within the actor group to which the actor belongs. The weights of these criteria for an actor specify the individual preference structure of that actor, which is the main factor that differentiates the decisions of different actors in the midst of identical option sets. For example, an actor giving more importance to familiarity characterizes a less innovative user, who prefers to comply with the historical choices of the group it belongs to. On the other hand, another actor weighing familiarity less is more inclined towards opting for innovative options; hence represents a more innovative profile. This preference structure is coupled with a variant of the *logit* function (Gensch and Recker 1979; Ben-Akiva and Lerman 1985) in determining the shift of end-user demand among electricity supply options.

As mentioned earlier, the model is an agent-based one, and the end-user agents in the model represent large groups of actors, rather than individual ones. Due to this actor aggregation, model agents represent large groups of actors as discussed above. Aggregation of discrete decisions of such a large group converges to a continuous process. Therefore, a continuous demand allocation formulation is used in the model: at the end of each year, *free demand* for each agent is calculated and allocated among feasible options according to the function used. *Free demand* is equal to the sum of two terms; the first of them is the total demand satisfied, during the previous year, via distributed generation capacity being depreciated, or grid-based supply contract being expired (i.e. replacement component). The second term is equal to the growth in the demand of the agent (i.e. expansion component).

Conventional gray electricity is accepted as the base-option in the model; the attributes of the gray electricity (e.g. cost of supply) constitute the reference levels to be used in assessing other options. For grid-based options, demand allocated to the option represents new supply contracts. For the other options, it indicates the need for capacity investment in that option. The generation capacity to be installed by the end-user is equal to the capacity that can supply the demand allocated to the option considering the technical properties of the option (e.g. seasonal availability). This way end-user groups manage their portfolio of supply sources, either by renewing grid-based supply contracts, or installing distributed generation capacity.

b. *Supply options and the generation companies*

The end-users discussed in the previous section constitute only one side of the socio-technical system. The other side of the story is related to the supply options, be them distributed generation technologies, or grid-based supply. The technical and economical attributes of the supply options are dynamic, and partially dependent on the endogenous dynamics of the system.

For the distributed generation options (i.e. all options except grid-based gray and green electricity supply), developments in technological and economical attributes of these options are introduced as exogenous processes into the model. In formulating exogenous technological or economical development of an option, it is assumed that development will continue with a decreasing rate, and eventually converge to a pre-defined future value (i.e. negative exponential growth). The specific values of initial, as well as future values for technical and economical attributes of options are given in the technical supplement, which is available from the authors upon request. In specifying these initial and final values, data introduced in (Lako and Seebregts 1998; Junginger, Agterbosch et al. 2004; Voorspools 2004; Breeze 2005; Caputo, Palumbo et al. 2005; Martinus, Blesi et al. 2005; Seebregts 2005; Freris and Infield 2008) are taken as the basis.

For the grid-based supply options, attributes such as cost of supply, price volatility and CO_2 emissions per kWh energy are directly determined by the available generator park, as well as the dispatching regime. Furthermore, profitability of certain generator types considered for capacity expansion, as well as operation hours of already existing generators are dependent on the demand pattern exerted by the end-users. Therefore, the provision system for the grid-based central supply options is included in the system boundary, and explicitly represented in the model. The grid-based system is introduced in two sections; the generation capacity, and the generation companies managing this capacity.

- Generation plants and import/export capacity

The set of central generation plants (i.e. generator park) constitutes the major technological part of the grid-based supply system. The Dutch generator park consists of around 60 active generators with generation capacities from 15 MWe to 695 MWe (Seebregts 2005; Rödel 2008). The generators also show variation regarding the generation technology utilized; hence the primary fuel used. As of 2006, 28% of the active generation capacity is coal-based, whereas 69% is natural gas-based. Borssele nuclear plant constitutes 3% in the Dutch central generation capacity. Besides these already operational generators, a set of new generators is already in the permission or construction phase. According to TenneT (TenneT 2007; TenneT 2007), an additional 10.000 MWe of capacity has been announced by generation companies to be operational by 2014. Approximately 40% of this new capacity is natural gas-based, whereas the remaining 60% is coal-based.

Each generator is represented by a discrete entity in the model. This representational choice is mainly driven by two issues that may influence the model behavior. First of all, generators are decommissioned in discrete chunks, rather than a gradual manner. The impact of discrete changes may have a different impact on the investment behavior of generation companies, compared to a gradual capacity decommissioning. Secondly, load dispatching is dependent on the technical and economic properties of the available generators. Aggregation of these properties and representing a group of generators as a single entity may yield different dispatching results. This difference will eventually yield different load allocation patterns, which is very influential in price and emission dynamics. Therefore, each *generator* in the model represents an actual generation plant, and its economic and technical properties are defined accordingly. A generator goes through three stages during its lifetime before being decommissioned; *announced*, *under-construction*, and *active.* All generation plants active as of 2006 are initialized using the technical and economic characterization reported in Rödel's dissertation (Rödel 2008). Additionally, expected capacity expansions in TenneT reports (TenneT 2008) are also introduced into the model as announced capacity.

- *Generation companies*

Generation companies are mainly responsible for short-term operation of the generators they possess, as well as long-term management of their generator park. The short-term operation mentioned above involves unit commitment decisions, and price bidding in the electricity market, which are directly related to load dispatching to take place in the market[3]. Regarding operational behavior, generation companies are assumed to be acting non-strategically. This implies two assumptions related to load dispatching. Firstly, it is assumed that they will not withhold generation capacity for strategic reasons, as it is discussed to be plausible in oligopolistic markets (Green 2004). Secondly, it is assumed that there is no inter-actor cooperation in price bidding to increase the prices in order to increase overall revenues, which is possible due to low price elasticity of demand.

Another short-term decision of generation companies is related to biomass co-firing. Most of the existing coal-fired generators can also use biomass-coal mixtures (up to 10-15% biomass) without significant loss of efficiency (Caputo, Palumbo et al. 2005; van den Broek, Faaij et al. 2008). Providers check the additional cost of shifting to co-firing against the additional benefits, make a fuel choice (coal alone, or biomass co-firing) for coal-fired options.

The long-term decisions of the generation companies are related to capacity management, i.e. investment and decommissioning. Generation companies periodically make an assessment of individual units in their generator park. In this assessment, decommissioning decisions are mainly based on expected lifetime of the technology used in a generation unit. A unit at the end of it is lifetime is decommissioned. Additionally, an old unit close to its lifetime may also be decommissioned if the unit has been making loss. Generation companies' expansion decisions are mainly driven by profit expectations. Capacity expansion decisions are dependent on four basic pieces of information; forecasts about fuel prices, forecasts about demand, forecasts about active generation capacity connected to the grid, and information about the feasible investment options.

The forecasts of the generation companies regarding the first three determinants of investment decisions are based on companies' perceived information about the market. This involves fuel prices, seasonal load levels, average electricity prices, and

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[3] *Load dispatching* plays an important role in average cost of generation, total emission levels, and profitability of generators. Therefore a more detailed description of its representation in the models is given in the appendix.

other revenue related quantities, such as market prices for carbon emission permits or green certificates. The companies utilize an adaptive trend estimation and univariate trend extrapolation heuristic to develop their future estimates regarding these key variables. In adaptive trend estimation, new information perceived by the agent at the end of each simulation step is used to update the historical average, and trend information. When necessary, this average and trend information is used to develop a forecast via simple extrapolation. It should be noted that, in implementing such a heuristic it is not claimed that actual generation companies are using a forecasting approach this simple. However, Sterman demonstrates that this heuristic imitates the forecasts developed by electricity utilities with a significant success (Sterman 1988). The adaptive trend estimation and extrapolation heuristic used in this model is identical to the one analyzed by Sterman, which is documented in detail in his work.

The forecasts of the generation companies regarding market conditions are used to evaluate available investment options. Expected cost and revenue figures are calculated for each option, and combining these figures with investment and fixed O&M costs, the company comes up with a return on investment (ROI) estimate for each option (Pirog, Stamos et al. 1987). The option with the highest ROI is selected for investment. If the highest ROI is less than expected ROI of the agent, which is 15% in the base case, the agent does not make any investment for capacity expansion.

As in the case of unit commitment, it is assumed that generator companies are not acting strategically in their investment decisions. Therefore, they only invest when there is room for profit. Strategic behavior that are plausible in oligopolistic electricity markets such as overinvestment for preventing new entrants, or inter-actor underinvestment cooperation for increasing prices are not covered in the current version of the model, but considered for future extensions.

While conducting the feasibility analysis briefly described in the previous paragraphs, agents rely on information they have about technical and economical properties of available options, such as electrical efficiency, availability, and variable O&M costs. Actors are not assumed to possess perfect information about these attributes. Therefore, actual investment options and information available to actors about these options are differentiated in the model. In the implementation, actors learn about improvements in the actual properties of options with a perception delay.

The generation unit options that are available for investment in the model are given in Table 2. Each option has a pre-specified generation capacity, which is derived from common commercial sizes (Breeze 2005; Rödel 2008). As in the case of end-user options, generation options' technical and economical properties develop over time in the model. The rate of this development is proportional to the gap between the current level of the attribute and the plausible future level. In other words, development rate is defined to be proportional to *room-for-development*. Current and plausible future values for technical (e.g. electrical efficiency, availability) and economic attributes (e.g. investment cost, fixed O&M cost) of options are determined based on recent studies on the issue (Lako and Seebregts 1998; Voorspools and D'haeseleer 2003; Vogstad 2004; Voorspools 2004; Seebregts 2005; Davison 2007; Rödel 2008; van den Broek, Faaij et al. 2008).

Table 2. Grid-based investment options available in the model

Option Name	Capacity (MWe)	Option Name (continued)	Capacity (MWe)
PC[4] (Single unit)	400	CCGT[5] (Single unit)	400
PC (Double unit)	800	CCGT (Double unit)	800
PC (Single unit) with CCS[6]	800	CCGT SOFC[7]	400
IGCC[8]	300	CCGT (Double unit) with CCS	800
IGCC with CCS	300	CCGT CHP	200
Gas Turbine	50	Nuclear	1000
Gas Turbine CHP[9]	50	Wind farm	20
Biomass/Waste Fired	10	Wind farm (Off-shore)	100

Although the set of options given in Table 2 is defined in the model, not all of them are available for investment in the beginning of the time horizon of the study. All options with CCS are assumed to be available for investment after 2025, considering legal and technological progress required. In the base run of the model, it is also assumed that the informal position of the Netherlands regarding nuclear energy (i.e. no further nuclear installations) will stay intact.

c. *Regulation of the market*

The Netherlands committed to the goal of increasing the share of renewable electricity generation, and the recent goal is declared as having 20% of the total electricity from renewable sources by 2020. In order to achieve this target, several policies have been used since early '90s. Despite having a meta-direction of greening the electricity supply, the Dutch government's preference has been towards generic policies, which does not focus on specific technology or applications. Both supply-side (e.g. investment support, or feed-in subsidies) and demand-side (e.g. taxing gray electricity) policies have been utilized so far. However, demand-side policies are not being used anymore, and the focus seems to be on boosting capacity investment via supply-side policies operationalized via SDE[10] program (SenterNovem 2009; SenterNovem 2009; SenterNovem 2009; SenterNovem 2009). Implementations of these policies showed significant variation within short intervals, which caused the Dutch renewable energy policy not having the best consistency record compared to other EU countries like Germany or Spain (van Sambeek and van Thuijl 2003; Junginger, Agterbosch et al. 2004; Agnolucci 2007). Since it is almost impossible to endogenously imitate such a policy implementation behavior in detail, a simpler approach is employed: it is assumed that the Dutch government will continue supporting capacity development in renewable electricity generation via increasing the economic competitiveness of renewable generation options, which is the main objective underlying various support policies recently employed. The state, as it is represented in the model, compensates renewable generation capacity via paying a

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[4] PV: Pulverized coal

[5] CCGT: Combined cycle gas turbine

[6] CCS: Carbon capture and storage

[7] SOFC: Solid oxide fuel cell

[8] IGCC: Internal gasification combined cycle

[9] CHP: Combined heat and power

[10] Stimulating sustainable energy production (i.e. Stimulering Duurzame Energiproductie, in Dutch)

subsidy per kWh electricity delivered to the grid, which is equal to the gap between the average market price of electricity and the cost of generation via that specific option. This is similar to the way the currently used SDE support program functions.

3. Simulation Experiments

The model introduced in the previous section, *i.e. ElecTrans*, is initialized in correspondence with the state of the actual system in 2006. Prior to full-scale experimentation, a thorough verification and validation process is conducted in order to assess the appropriateness of the model. Verification process, simply, covers the assessment of the model in terms of implementation problems (*i.e.* precision in converting the conceptual model to the computer environment). In this case, it is conducted via extensive code walk-through tests, as well as input-output tests for isolated sections of the model. Validation involves the assessment of the model structure as well as the model behaviour. The structure of *ElecTrans* is validated via several tests, such as isolated behaviour plausibility, and extreme value tests. However, an extensive behavioural validation was not possible due to the inappropriateness of the historical data from the actual system for such a procedure. Since the Dutch electricity system has been going through an important liberalization process, the historical data before and after this process is generated by different system structures. Since *ElectTrans* corresponds to the post-liberalization structure, historical data from the pre-liberalization period is not a meaningful input for a behaviour validation test. Therefore, only a limited behaviour validation procedure could be conducted.

Considering the technological, social and economical aspects, *ElectTrans* provides an environment for a wide range of experiments. Only a limited subset of such experiments, which is selected on the basis of contextual relevance, is reported in this paper. First of all, it is aimed to present the plausible directions of change for the Dutch electricity system under commonly discussed developments, such as the rapid improvement of clean coal technologies, or the policy interventions leading to more expensive carbon emission permits. As will be apparent in the discussions, the simulation results are not considered as future predictions for the Dutch electricity system, but these results are used to develop a better understanding about the way the Dutch electricity system may react to particular type of changes.

For each case to be discussed below, multiple simulation replications are performed. This is mainly due to procedural processes related to the agent-based simulation that are probabilistic in nature, such as shuffling the order of the agents before each decision round. In order to filter out the impact of such probabilistic processes on the conclusions to be drawn, 50 replications are performed for each case, and the mean values of these replications are presented during the discussions, unless otherwise indicated.

a. Base case

This case constitutes a basis for comparison for the analysis. The case assumes the continuation of the recent trends with no major changes. In relation to technology, this translates to a normal technological development pace, as well as a normal innovation climate. All generation technologies available in the beginning of the analysis period are assumed to develop according to the widely accepted trajectories. In other words, their technical and economical properties, such as investment cost or electrical efficiency, converge to the *most likely* values discussed in the literature. Also no significant shift in the commercial introduction of new options, such as carbon capture and storage, is expected in the case. The context in which the end-users and the generation companies act is mainly defined by the fuel prices and the regulations in the model. Regarding the fuel prices, it is assumed that the coal and natural gas prices will follow their historical growth averages. Initial fuel prices and corresponding yearly increase percentages are given in Table 3.

Table 3. Fuel prices in the base case

Fuel	Initial price	Price change per year (%)
Coal	1.8 Euro/GJ	1.5
Natural Gas	4.2 Euro/GJ	2
Biomass	5 Euro/GJ	0
Uranium	4.5 Euro/MWhe	0

The regulator is assumed to continue supporting the renewable generation options according to the currently dominant perspective of making them economically competitive against the conventional technologies. Uncertainty is quite high regarding the evolution of the carbon permit-related policies beyond 2012. Both the commitments on total emissions as well as the national permit allocation schemes may undergo significant changes, or may stay as it is currently. In the base case, no significant change is assumed. In accordance with that, the emission permit prices are assumed to continue to settle around the current insignificant levels (i.e. below 10 Euro/ton $C0_2$).

No significant change on the end-users' side related to the norms and priorities is expected in this experiment. Therefore, the preference structures, which are represented by the weights of different objectives as discussed before, that guide the actions of these actors stay the same throughout the simulation run.

The base version of the model is simulated for the 2010-2040 period. The dynamics regarding the primary choice of the end-users indicate that an increasing share of the aggregate end-user demand is directed towards the grid-based electricity supply options (Figure 2). The first decade of the simulation, a steady increase in the share of the distributed generation is observed. This increase, which can be misinterpreted as an early transition phase, ceases after the first decade, and the share of the distributed generation falls below its initial level of 30%. The factors that lead to this growth-and-decline pattern in the share of the distributed generation, which can also be characterized even as a backlash of a transition towards a decentralized structure, are discussed in the following paragraphs. Figure 2 also shows that the grid-based supply prevails as the dominant supply option, and, furthermore, most of the demand directed towards the grid-based supply is for the traditional gray electricity. In order to understand the factors leading to this outcome, a closer look at the system is required.

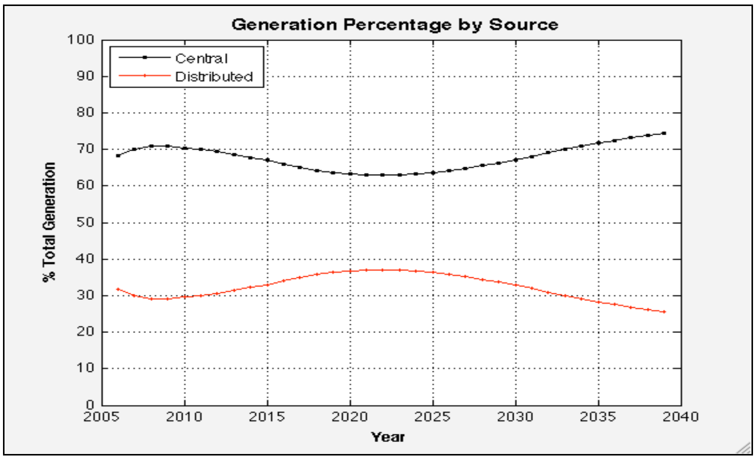


Figure 2. Allocation of end-user demand between central and distributed supply

The breakdown of the distributed generation according to the energy source is presented in Figure 3, which shows the aggregate situation over all end-user groups. Further breakdown of the distributed generation according to end-user groups can be seen in Figure 4. A significant decline in the natural gas-based supply is observed in the figure. One of the underlying causes of such a development is the increase in natural gas prices. The flagship of distributed generation is gas-fired CHP facilities in the Netherlands. However, this option loses its competitive advantage, even considering the benefits from cogeneration, due to high gas prices and discontinuation of former cogeneration support schemes. As a result, only very limited replacement investments are observed against a continuing retirement of the existing CHP capacity. Only for household users, an insignificant increase in natural gas-based generation is observed, which is due to limited diffusion of micro-CHPs. This constitutes one of the issues related to the decline in the share of the distributed generation in the system.

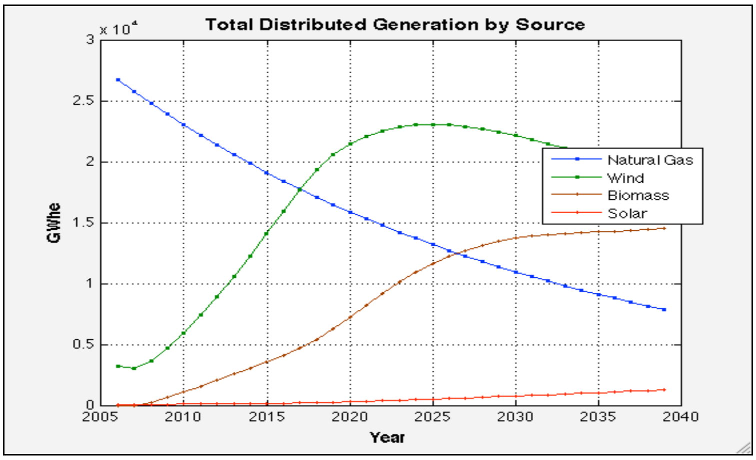


Figure 3. End-users' electricity consumption by energy source (aggregated over all end-user groups)

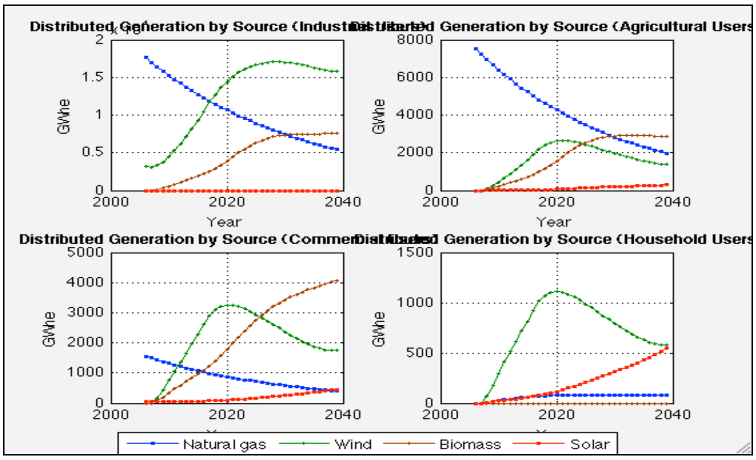


Figure 4. End-users' electricity consumption by energy source

An important increase in the amount of electricity generated via green options, especially via biomass and wind-based options, is observed during the first half of the simulation. This growth compensates the aforementioned decline in natural gas-based generation, and yields the growth in the share of the distributed generation. The pace of increase stagnates in the second half of the simulation, and even a slight decline in the wind-based generation is observed (see Figure 3). Going over the major relations depicted in Figure 5, it is easier to understand the factors behind this stagnation. In the growth phase, the SDE support scheme, which supports the green generation via compensating the cost gap between the grid-based and the green electricity, is the main factor behind the increase. However, SDE makes green options equally cost competitive with grid-based options, but not more profitable than that. Hence, the critical push factor is the extra benefit obtained from green certificates, which fluctuates as a consequence of the balance between green electricity supply and demand. However, the negative feedback loop L1 in the figure pulls the certificate prices down. Observing the demand-supply dynamics for the green electricity presented in Figure 6, it is clear that this extra benefit diminishes as a supply surplus situation emerges over time.

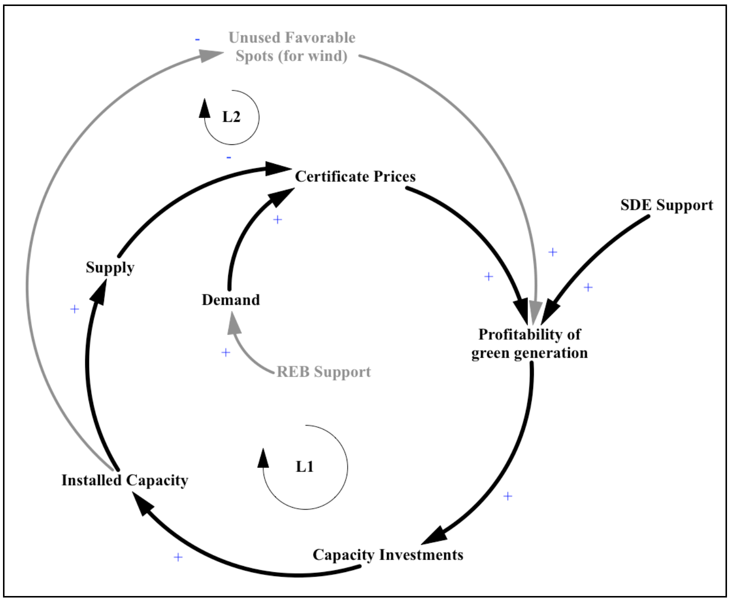


Figure 5. Demand-supply interaction for the green generation capacity

One way to neutralize the impact of this negative feedback loop is to support the demand growth. However, in the absence of demand-side support policies (like REB which was abolished in 2004), the green electricity loses its economical appeal for the end-users, and its utilization is confined only to the environmentally friendly end-users. In summary, in the absence of policies like REB, the demand growth stagnates, leading to the dominance of L1 in pulling down the capacity investments.

Apart from this, there is a secondary factor that plays an important role in the growth of wind-based generation: carrying capacity. The surface area where wind turbines can be located, due to both wind availability and environmental concerns, is naturally not infinite for inland projects. Due to significantly lower installation costs, inland turbines are the most profitable wind-based generation option in the model. Hence, in the early phase most of the investments are for inland wind turbines/farms. Increasing costs, due to less favourable locations, for the inland wind turbines is the secondary factor that slows down the growth in wind-based generation. Going back to Figure 5, this means that there is a second negative feedback loop that counteracts the growth in the wind turbine installations, *i.e.* L2.

Finally, PV rooftop panels emerge as an important distributed generation option, especially, for household users. Since the model does not consider surface area issue for PV panels, the extent of the solar-based generation should be evaluated with caution. Despite this caveat regarding the limits of solar-based generation, it is seen that it may establish a position in some market niches.

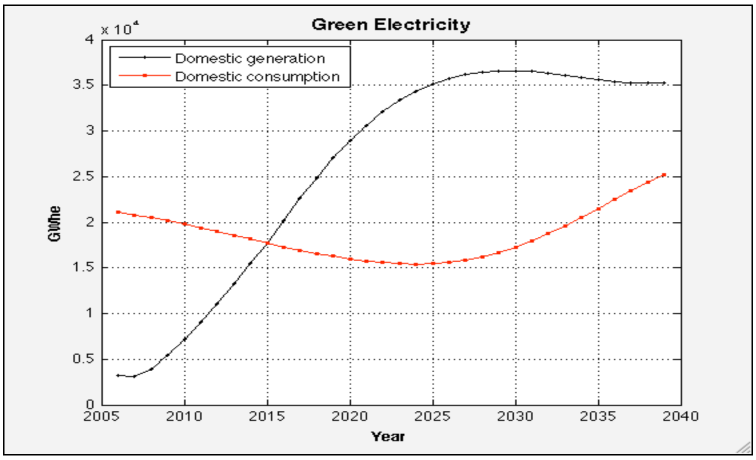


Figure 6. Total green electricity consumption vs. generation

As already discussed in the beginning, end-users' choices over time indicate a growing load on the central grid, and in the absence of a significant increase in the distributed supply this growth may be even more than expected. The development of the load on central generation system, as well as the evolution of the installed capacity is given in Figure 7. A striking observation is a significant over-capacity during the early phases of the simulation. Rather than being a result of endogenous investment behaviour of the model agents, this over-capacity is rooted in the behaviour of the real generation companies. The bulk of generation capacity that is commissioned before 2015 is the set of generation plants already announced by the generation companies and reported by TenneT (2007a). This covers an approximate total of 8500 MWe generation capacity, for which TenneT has already entered into connection agreement as of 2009, and excludes other announced plans without a connection agreement. As seen from the figure, the load on the central grid is increasing very slightly, and almost constant in some periods, during the 2010-2015 period. Despite the growth in total electricity demand, only a small portion of this growth is felt on the grid, since increase in the distributed generation compensates some of that demand increase. However, following the decline in the share of distributed generation, the load on the central grid enters the faster increase phase observed beyond 2020. In short, it is the dynamics on the distributed power generation side that causes the change in the pace of the load growth, rather then the actual growth in electricity demand.

The aforementioned issue shows a novel complication in the electricity supply system; increasing demand flexibility. This poses a great uncertainty for the generation companies. When the central grid is the only option for the end-users, the key forecast to be made for the capacity investments is about the increase in the demand of the end-users. However, with the increasing number of options for the end-users, additional dimensions are required in the forecasts, such as the end-users' investments in distributed generation capacity. Although this is not something we directly observe in our simulations, the increasing uncertainty about the demand may lead to risk-averse investment behaviour in the multi-actor liberalized market setup. Eventually, this may cause problems such as insufficient generation capacity in the long run.

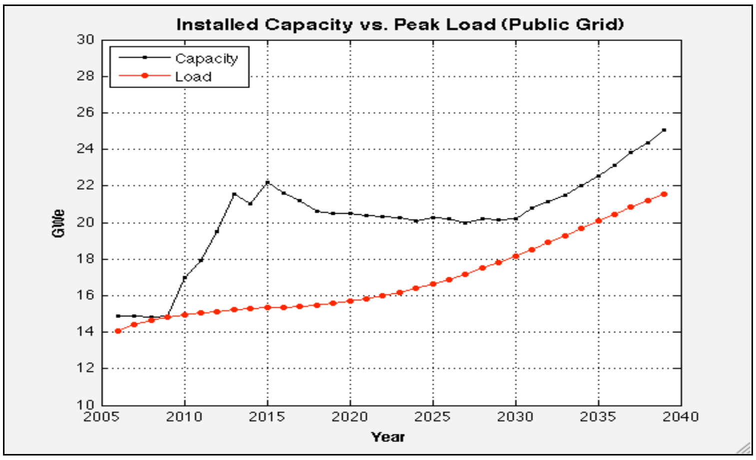


Figure 7. Installed capacity vs. load on the central grid

The over-capacity situation that is observed in the beginning of the simulation has a set of consequences. Firstly, it causes a decline in the average price of the grid electricity (see Figure 8). This is mainly due to upcoming coal-based generators capturing the share of the gas-based generators in the market. A more indirect consequence of the over-capacity situation is the investment barrier it yields. The generators connected to the central grid are high value investments with long lifetimes (e.g. 20-30 years). Due to the value, they constitute important commitments for the generation companies: their likelihood of shifting to alternative generation technologies is very low as long as these commitments exist. Additionally, they are also very likely to demonstrate strong fight-back reflexes against any new entrants through price competition. This means that there is no major possibility of altering the generation park until 2020 since new investments are not promising in such a system state. In other words, any policy intervention during this period will only have impact on the short-run operational decisions, but not that much on the way the generator park evolves. The model agents' tendency towards not making any capacity investment until the 2020s is a reflection of this problem in the simulation runs.

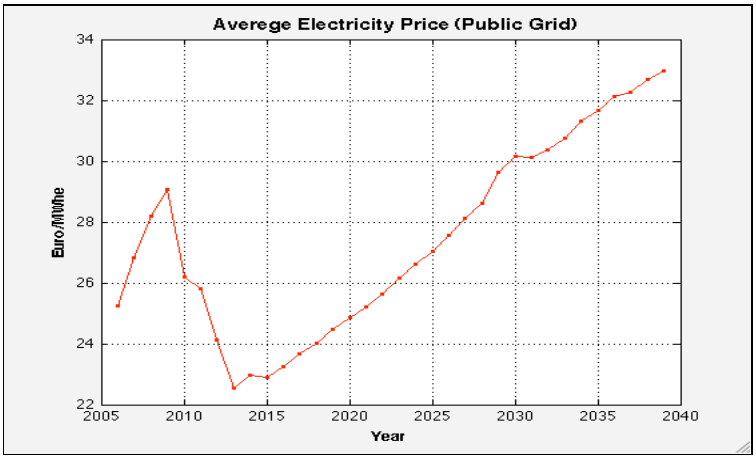


Figure 8. Average electricity price (public grid)

The investments in the central generation system are dominated by the coal-based options even beyond the initial over-capacity period. Among others, the IGCC plants emerge as a favourable generation option. The consequence of this investment tendencies over time lead to the shift of dominance from natural gas to coal in the Dutch central generation system. Towards the final periods of the simulation run, natural gas-based generators only supply electricity for peak and a portion of the medium load, whereas base load is almost totally supplied by coal-based generators. Since there is no significant emission penalty in the base case, CCS is not adopted at all, causing increased emission levels

This is partially understandable considering the marginal fuel cost advantage over the natural gas-based generators, and the lack of significant carbon emission penalties. However, the coal-based generators typically serve base load. In more practical terms, it makes sense to invest in a coal-based generator only if the generator is expected to be generating electricity with a high utilization level (e.g. 70%). This puts a constraint on the expansion of the coal-based generators. However, as it is seen in Figure 9, this constraint does not seem to be very strong for the Dutch system.

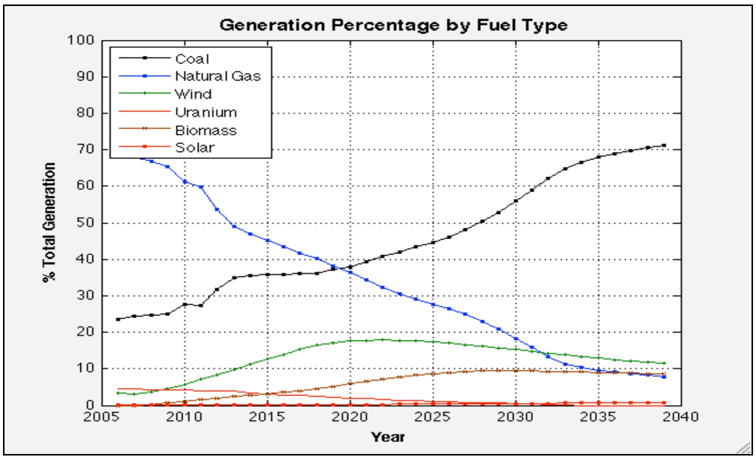
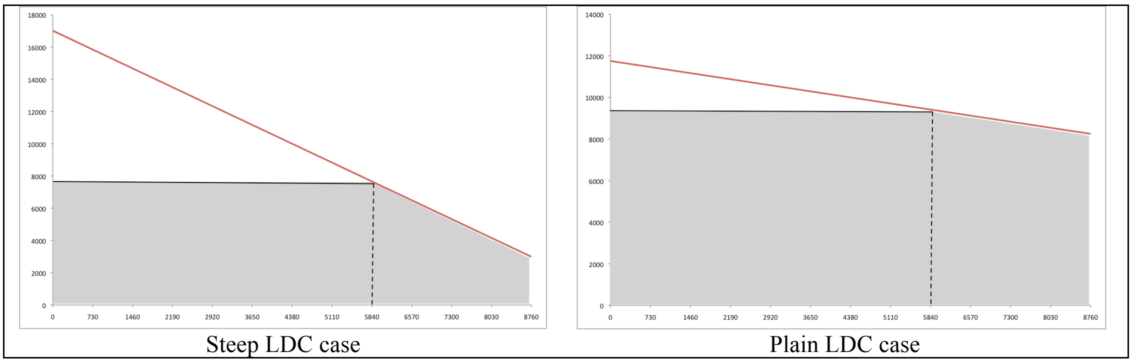


Figure 9. Share of primary fuels in total central generation

Triggered by this observation from the simulation results, we further investigate the issue, and the character of the Dutch load duration curve (LDC) (more specifically the slope of this curve) is identified to be the main factor in creating such a coal-friendly environment. Figure 10 demonstrates two simplified LDCs with different slopes. The areas underneath the curves are equal; i.e. the total energy demand is the same, but the pattern of the demand is different. In these two cases, we consider the situation of a base-load generator that needs to be active at least 67% of the time in a year. The shaded areas represent the part of the total demand that can be served with this particular generator. Clearly, this part gets much larger when the LDC gets less steep. The Dutch LDC, not being steep one, provides a large room for the coal-based generation, and this explains the extent to which the share of coal-based generation can increase in the simulations.



Steep LDC case

Plain LDC case

Figure 10. Example about the role of the slope of LDC on the share of the base load

Figure 11 presents the carbon emission related consequences of the generation portfolio evolution. The emissions increase only slightly during the pre-2020 period. Beyond this point, combined impact of two factors result in a significant growth pace in emissions: first of all the demand on the central grid increases faster; secondly the share of coal-based, i.e. 'dirty', generation in the central generation increases during the same period. Hence, significant emission levels are reached in the absence of emission prevention measures, limited diffusion of green generation and no interest towards CCS applications in the base scenario.

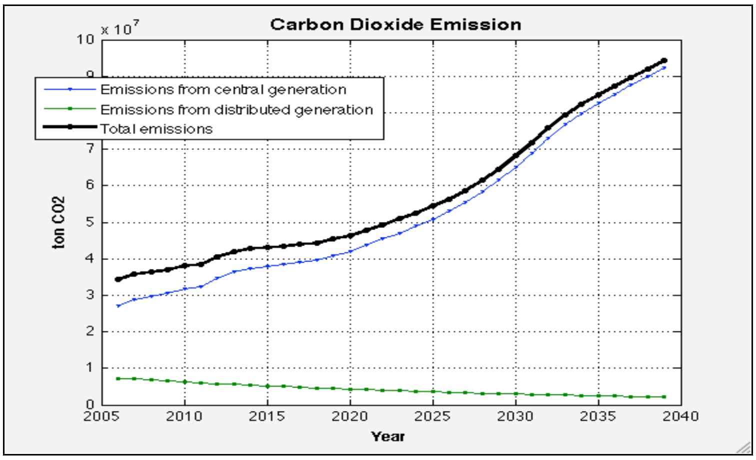


Figure 11. Carbon dioxide emission due to electricity generation

b. Strong regulatory pressure for change

The results obtained from the base case show that intrinsic processes of the energy system is not likely to lead to a transition when left alone. Such a result should not be surprising. Additionally, the carbon emission levels experienced in the base case seem to be unacceptable within the contemporary European context. Therefore, the second scenario includes a strong regulatory pressure for *'de-carbonizing'* the system, and investigates the plausible developments within the system triggered by such a pressure.

Currently, the national emission commitments beyond 2012 are not clear, and the ambitions of EU and the member states beyond that time point carries significant uncertainty. In this scenario, it is assumed that the Dutch government, as well as other EU states, pushes harder for emission reduction. This can be conceptualized as allocation of fewer permits, which should eventually lead to increasing permit prices. In initializing the model for this experiment it is assumed that the permit price increases until 2020 reaching 60 €/ton carbon dioxide emitted, and then stays at that level until the end of the time horizon. Although there is no common expectation about the future levels of the permit price, a price above 40 €/ton is evaluated to be a significant penalty.

Different from the base scenario, the share of the distributed generation shows a growth in the final decade of the run in this scenario (Figure 13). This late increase is primarily related to the increasing gray electricity prices: the grid-based supply option loses its cost advantage against the distributed generation (especially against the wind-based generation) due to this price increase. However, this does not explain why there is no change in the early periods despite the significant increase in the prices from the very beginning of the run. An intuitive expectation would be a much earlier increase in the share of the green generation as the carbon permit price increases. The explanation can be found in the way the current sustainable energy support program (i.e. SDE) works: SDE does not provide a fixed feed-in tariff for renewable generation, but it provides a dynamic support to compensate the gap between the price of the grid electricity, and the cost of renewable generation. Therefore, as long as the grid-based electricity's price stays below the cost of generation via wind, the wind-based generation will not gain an extra competitive advantage as a result of the increases in the grid electricity prices. In other words, SDE acts like a buffer, and makes the system insensitive to price changes as long as grid-based electricity is cheaper than the distributed generation.

In this scenario experiment, we also observe interesting consequences of the way different policies interact within the current setup of the Dutch system. SDE is a policy scheme that aims to increase the electricity generation via renewable options. The carbon penalties are used in order to steer the system away from carbon-intensive generation methods. At the first glance, these two policies are both against the fossil dependency, and may be expected to have a stronger impact on the system when used simultaneously. However, the simulation experiments do not support such observations. The permit costs are reflected in the cost of generation, and this increases the marginal generation cost of the grid generators. This results in the permit costs being transferred to the end-users; i.e. higher electricity prices. In the same time, due to higher grid electricity prices, the subsidies to be paid by the state to renewable electricity generators decreases: the gap between the marginal generation costs of grid-based and distributed options get narrower. This can be seen in the illustration given in Figure 12. As an overall consequence, the tighter carbon permit allocation policy used by the state shifts the burden to end-users. The renewable generation options are supported to the same level as in the case of the base scenario, total subsidy to be paid by the state is less, and end-users are facing more expensive grid electricity. This can be evaluated as an unintended joint consequence of two separate, but interrelated policy interventions.

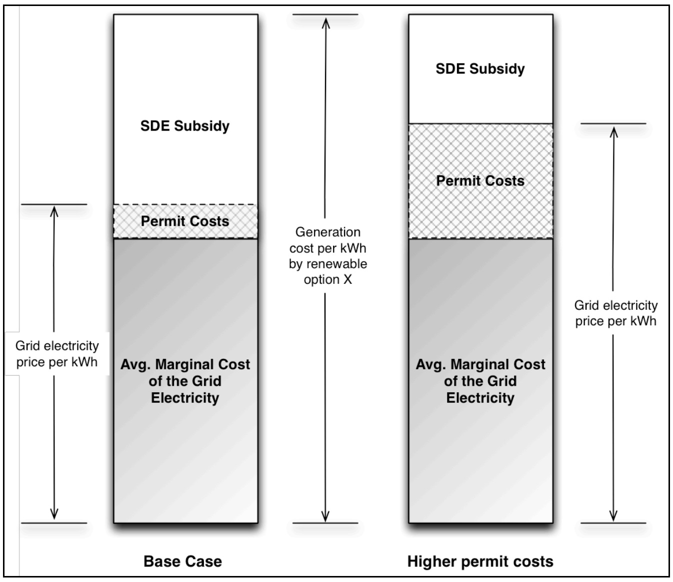


Figure 12. Composition of electricity prices with the SDE subsidy

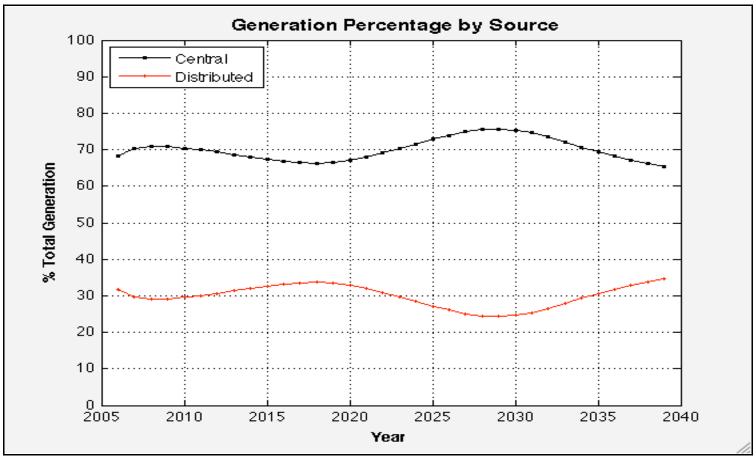


Figure 13. Allocation of end-user demand between central and distributed supply

Some significant differences are observed with respect to the dynamics of distributed generation (Figure 14). First of all, the decline in natural gas-based generation ceases towards the end, and even a slight increase is observed. This can be explained by increasing cost competitiveness of small-scale generators despite the increase in natural gas prices, since they are excerpt from carbon payments[11]. Secondly, wind and biomass-based distributed generation follow different trajectories in this scenario. Until 2025 generation costs of the both options are higher compared to the grid-based generation. Therefore they are both supported via SDE. Since SDE provides a subsidy to compensate the difference from the grid-based generation (i.e. options get different levels of subsidy, and their generation costs are made equal with this support), there is no difference between the wind and biomass options. Beyond 2025, average cost of

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[11] Generators with an output capacity below 20 GWh are excluded from the carbon permit market

grid-based electricity exceeds the cost of wind-based generation. However, biomass-based generation is still more expensive. This marks the point where wind obtains a financial advantage over both grid-based supply and other distributed generation options. This causes the decoupling of the dynamics related to the biomass and wind-based generation: one experiencing a steep increase, while the other barely sustaining its share in distributed generation.

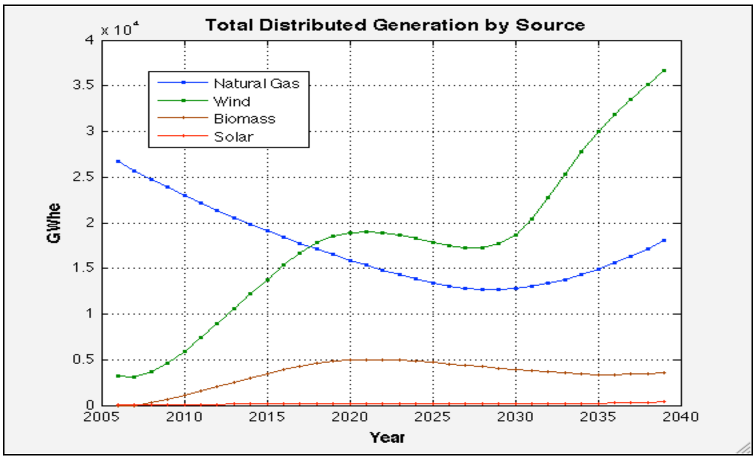

Figure 14. End-users' electricity consumption by option

When the situation for the central supply system is examined, a totally different picture from the base experiment is seen (Figure 15). Three periods can be identified for the central supply system. The first one is the pre-2015 period, which resembles the same period from the base case. A decrease in the share of natural gas, and a corresponding increase in the share of coal are observed in this period. Beyond 2015, the impact of the high permit price becomes visible. The natural gas-fired generators having much less emission levels (i.e. almost 50% less per kWh electricity generated) become economically competitive against the coal-fired generators, and re-gain their share in total generation. This happens through the increase in the share in load dispatching in the short run, and through the increase in the investments to gas-based options in the longer run.

Another development is the increase in biomass-based generation. This takes place in the form of co-firing in central coal-fired plants. Once permit prices exceed a threshold beyond which emission reduction due to biomass co-firing compensates the extra cost of biomass, generators start shifting to biomass co-firing. The situation between 2015 and 2025 seems like coal is about to disappear from the Dutch system. However, a strong comeback is seen beyond 2025. One important factor in this come back is the increase in the natural gas prices, which causes the emission advantage to erode against the coal-based generation. The second factor is the commercial availability of CCS, which eliminates the emission disadvantage of the coal-fired plants. Such a rapid change in the economic competitiveness of options leads the sharp shift in the shares of coal and gas in central generation.

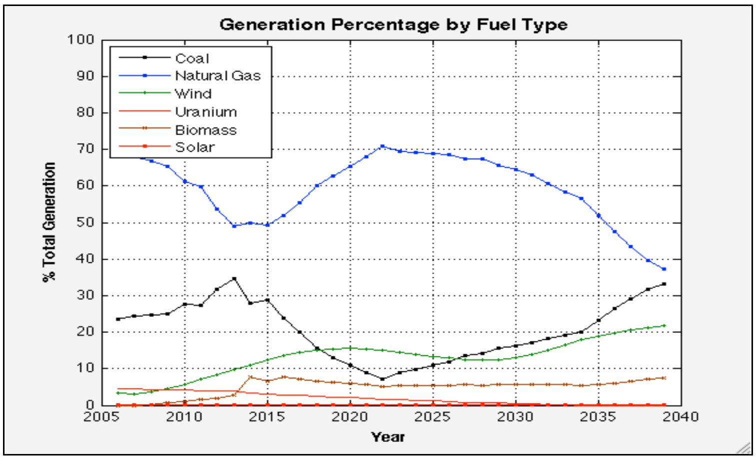

Figure 15. Share of primary fuels in total central generation

The observed changes that related to the comeback of the cola are very rapid for a capital-intensive system like the electricity supply. There are a couple of issues that set the scene for such rapid changes. First of all, both investment and load dispatching processes are driven predominantly by purely economical concerns. In other words, there is one property of the options that dominate the decisions of the actors; i.e. the generation cost. However, the nature of this property is reversible: any development in this property may be reversed in a very narrow time window. This is exactly what happens in this case. Increasing natural gas prices, and the introduction of CCS yield a very rapid change in the relative costs of the coal-based and gas-based options. The dominance of a single reversible property in the actor decisions is the primary factor behind this comeback.

Secondly, the liberal market structure with multiple actors also enables such a dynamic behaviour. Since the agents in the model are maximizing their individual profits, they see no problem in making investments that will make other agents' investments redundant. This yields to an overcapacity situation where some of the gas-based investments become unprofitable, and practically passive much before completing their lifetimes.

As a result, we observe that if the (desirable) changes in the system are dependent on reversible developments, precautionary measures for 'anchoring' these developments may prove useful. For example a progressive carbon permit price that follows the increase in natural gas prices would help to sustain the cost advantage of the gas-based generation. In other words, it would help to anchor the gained advantage. Secondly, rapid changes in the relative situation of the competing options are observed to have the potential to lead to overcapacity situations in multi-actor settings such as the electricity markets.

c. *Optimistic technological development scenario*

One of the uncertainties about the future of the electricity supply is related to the extent of the technological developments. Some optimistic scenarios claim significant room for development for the green technologies in economic (e.g. investment and operating costs) and operational performance (e.g. efficiency, capacity availability). On the other side, new innovations and technological developments are also expected related to the fossil fuel-based conventional technologies. This scenario explores the impact of such optimistic technological progress: the development limits of the properties of different options are raised, and the widespread introduction of the new technologies (e.g. CSS, SOFC, IGCC) takes place earlier. The modified parameter values corresponding to these changes can be found in Appendix C.

Despite the aforementioned changes, the major behaviour patterns are observed to be very similar to the base case. This behavioural insensitivity is mainly due to the SDE policy, as discussed already in the previous scenario experiment. The economical properties of the distributed generation options are more favourable in this case, but this development is not likely to make them cheaper than the grid-based supply. As long as this is the case, the changes in the economical properties of the options only change to subsidies to be paid by the state (i.e. generation costs are lower, and the gap to be compensated by the subsidy is less), but fail to provide the extra push to initiate a system-wide transition.

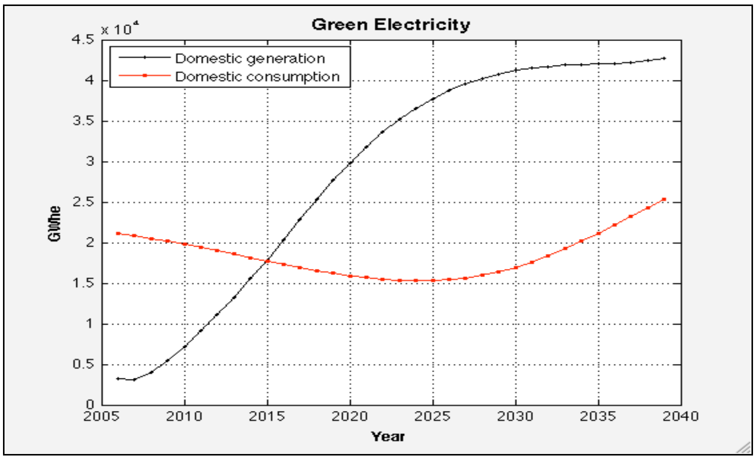

Figure 16. Demand vs. supply of green electricity

The share of the grid-based generation, as well as the composition of the capacity connected to the central grid is almost identical to the base case. Slight changes are observed regarding the composition of the distributed generation: first of all there is some increase in the domestic green electricity generation, despite the absence of an increase in the demand for green electricity. This is mainly triggered by the slight increase in the economic viability of the biomass-based options. When the situation of the end-users is studies, it is observed that PV panels and m-CHPs obtain a higher share in the supply portfolio for the household-type end-users. However, the impact of this is a negligible development when the aggregate situation over all end-user groups is considered.

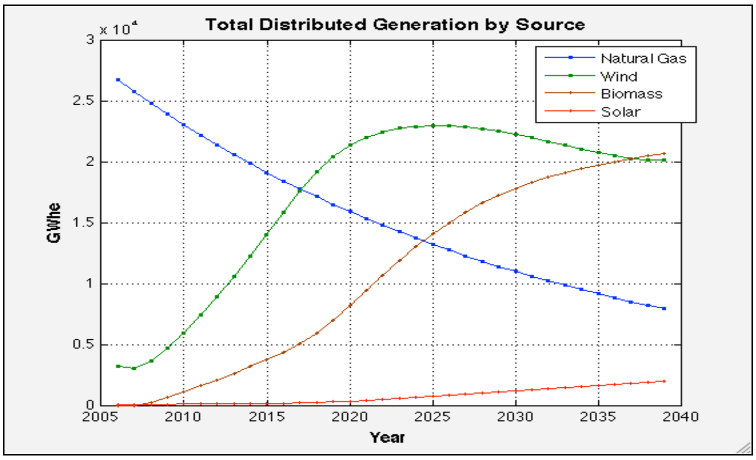

Figure 17. End-users' electricity consumption by option

This scenario experiment reveals the behavioural insensitivity of the Dutch electricity supply system to technological uncertainty under the current SDE support scheme. Naturally the insensitivity mentioned here is within the time horizon of the runs. The delays in the development of the generation options, and their active utilization (adoption, investment, etc.) create a sort of systemic inertia. In the presence of such inertia, it is difficult to observe significant changes in the system even under optimistic condition.

Before proceeding, it should be noted that the exploring the technological uncertainty demands much more than just considering optimistic development trajectories for some options, as we do in this experiment. This experiment is conducted just to explore if any of the currently available novel options will stand out in case it develops beyond the common expectations.

***d. 'Greening end-users'* scenario**

The final scenario to be discussed in this chapter is related to the plausible changes in the electricity supply system due to significant changes in the preferences of the end-users. Since the end-users, and more specifically their *behavioural identities*, are explicitly represented in the *ElectTrans* model as a vital aspect of the socio-technical system, the model allows us to conduct such experiments.

As already mentioned, the different end-user groups are characterized according to the scale of their electricity demand, and their preferences that guide these users in their supply choices. In this scenario, the priority of the environmental issues experience significant increases for all actor groups. In a way, the environmental concerns gain some priority for all actors in comparison to the purely economical concerns. In line with this, a steady 'greening' takes place among the household-type users during the simulation run: the environmental friendliness (i.e. carbon emission in this context) becomes the primary criteria for supply choices by the end of the time horizon. A similar development takes place for the agricultural and commercial end-users. They go through a slower preference shift, and environmental friendliness becomes equally important with economical ones. Industrial users also experience some level of 'greening', but the economical aspects still dominate their choices through out the time horizon of the analysis.

The changes in the end-users' preferences trigger a demand formation for the green electricity. Being the readily accessible and most cost-competitive one, the grid-based green electricity attracts most of this newly forming demand. As seen in Figure 18 the demand for green electricity makes a steeper climb compared to the base scenario. As a consequence of higher levels of green electricity demand, the supply surplus diminishes towards the end of the time horizon, which increases the green certificate prices. This latter increase provides an incentive for further investment and green capacity, hence the green generation, continues to grow throughout the time horizon, rather than stagnating, as it was the case in the base scenario. This observation also supports our previous conclusions in the base case regarding the interplay of the demand and supply of green electricity.

The early supply surplus and the intrinsic investment delays create some level of inertia within the system. As a result, the impacts of the preference changes that start around 2015 on the green generation dynamics are only felt beyond 2025.

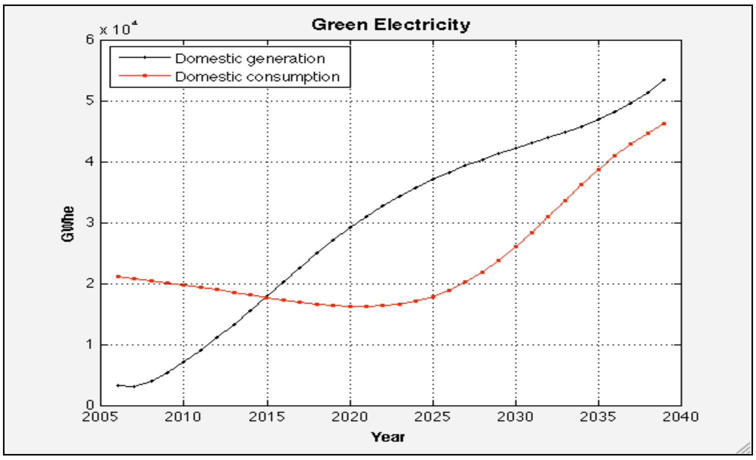

Figure 18. Demand vs. supply of green electricity

The aforementioned increase in the green certificate prices provides an extra push for green distributed generation options. This keeps the share of the distributed generation at higher levels compared to the base scenario. Although it is not possible to talk about a notable increase, the share of distributed generation sustains the %40-level (Figure 19).

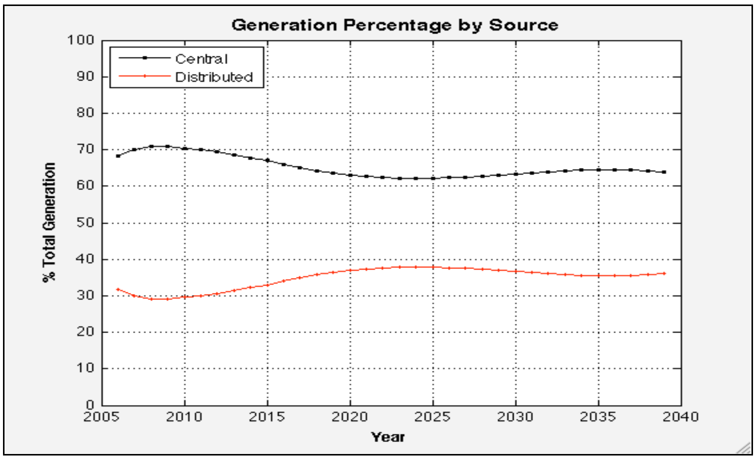

Figure 19. Allocation of end-user demand between central and distributed supply

As seen in Figure 20, the biomass-based generation experiences a steady increase, while the wind-based generation stagnates following an early rapid growth. Being an initially more attractive option, wind-based generation demonstrates an earlier growth. However, once the favourable inland spots are used, the cost of capacity expansion gets less attractive for the wind farm installations. This can be considered as a consequence of the capacity crowding dynamics, where the favourable spots for the inland wind farms constitute a natural capacity limit beyond which the options starts losing its economical attractiveness. As a result, as the limits of land-based wind installations are approached, biomass captures the economic advantage and attracts most of the demand for green electricity generation. This indicates that being an option that has the potential to experience an early take-off, the wind-based generation may be unable to sustain this growth unless the technological developments close the gap between the already favourable inland and other wind farm installations in economical terms.

The shift of demand to green distributed supply options results in a slightly less load on the central generation plants compared to the base scenario. This slight decrease does not have a major impact, and the dynamics regarding the central generation are pretty similar to the base case. When the overall system is investigated, the dependency of the system on conventional fossil fuels is intact (Figure 21). The shares of energy sources, except biomass, have very similar dynamics with the ones observed in the base case. As briefly discussed above, the extra demand for green options triggered by the general greening trend among end-users yield an increased share for biomass-based electricity generation in the Dutch context. This indicates a very strong internal inertia in the system that is hard to overcome just by changes in the end-user preferences. At least, a change at the scale that is considered in this experiment only has a marginal impact on the system.

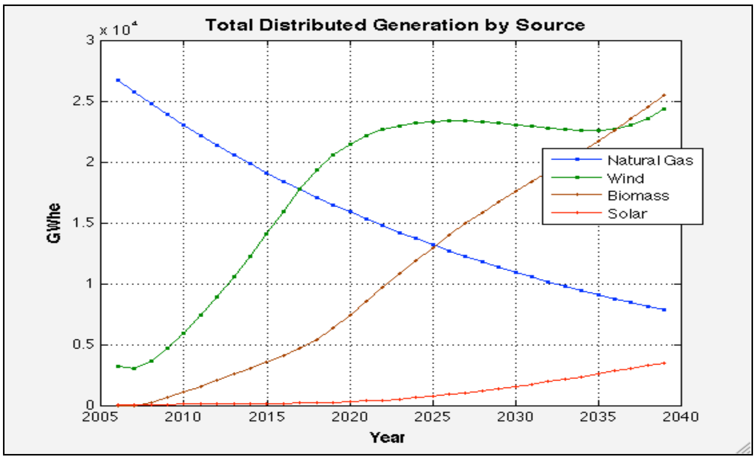

Figure 20. End-users' electricity consumption by option

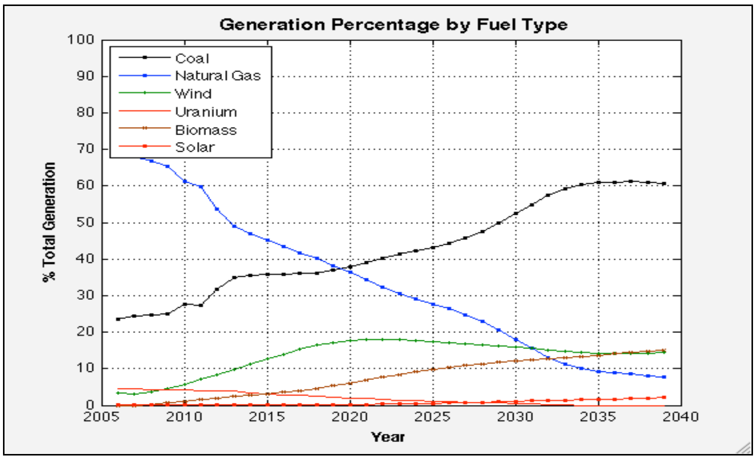

Figure 21. Share of primary fuels in total central generation

4. Conclusions

The Dutch electricity supply system is going through an era that can be characterized with changing institutional, economical, technological and social conditions. Despite the intrinsic inertia against change, which is typical to large-scale socio-technical systems, these changing conditions create a backdrop of change for this system. This study aims to explore the extent of change that may be expected, and plausible development directions under recent conditions.

The electricity system is an interconnected constellation of actors, technologies and infrastructures. The feedbacks among these components, and delays embedded in their interactions cause such a system to possess high-level of dynamic complexity. Therefore, a dynamic simulation model is utilized to analyze the system behavior under differing conditions. A simulation model that incorporates both the demand and supply sides of the system is developed, and calibrated to represent the Dutch electricity system. The model builds upon fundamental system dynamics notions, and utilizes an agent-based architecture to formalize the conceptualization of the system.

The reference scenario experiment indicates that central generation sustains, and even extends its share in the supply of electricity. This indicates the deterioration of the current important position of distributed generation in the Dutch context. As a direct consequence of the opening gap between coal and natural gas, future capacity expansions are likely to be dominated by coal-based generators. Lack of significant carbon penalties, and the relatively flat load duration curve of the Dutch electricity demand enable such a development. The second scenario addresses one of these points by introducing progressive carbon permit prices. Such a high penalty on carbon emissions suppresses coal-based investments, the development of the grid-based generation capacity changes significantly. However, it is seen that unless the progress in the penalty keeps up with the price gap between coal and gas, a strong comeback of coal-based generation is possible. This scenario also demonstrates that greening and de-carbonizing policy measures are closely related, and rapid increases in the carbon prices may result in the transfer of greening program costs directly to the end-users. The third scenario depicts an optimistic technological development situation. This scenario experiment reveals the behavioral insensitivity of the Dutch electricity supply system to technological uncertainty under the current SDE support scheme: even with optimistic development trajectories, the impact of this development on the system is observed to be insignificant within the considered 30-year time horizon. The last scenario reported in this paper addresses the issue of *'greening'* end-users. A significant preference change in favor of environmental issues results in an important increase in the demand for green electricity. This demand-push yields an increased green capacity build-up compared to the reference case. However, the extent of this increase is still limited considering the total electricity supply.

The system boundary used for this analysis is quite broad, and incorporates many social and technical uncertainties. Due to space constraints only a small set of experiments, which are considered to be relevant within the current policy debates are discussed in this paper. In the course of on-going analyses, the model is being used for extensive exploration, as the wide system boundary demands. This uncertainty exploration goes beyond simple single-parameter sensitivity analysis, and includes even sensitivity analysis based on different behavioral routines of the actors; a feature that is possible in the agent-based architecture used. Analyses of the results obtained from this exploration stands as the follow-up of the work reported in this paper.

Considering the implementation, some discrete processes in the electricity supply system, and the potential importance of actor heterogeneity made an agent-based architecture more suitable for this analysis. Despite benefiting from an architecture that is non-native to the system dynamics field, the system representation extensively relies on system dynamics concepts. In that respect, this study can be considered as a typical example of mutualism between the established conceptualization and analysis tradition of the system dynamics, and flexibility of object-oriented implementation.

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