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Short-term Effects of Long-term Policies: Climate Policies in Power Markets

Kortsiktige virkninger av langsiktig politikk: Klimapolitikk i kraftmarkedet

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DOCTOR SCIENTIARUM THESES 2007:11

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Contents

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Introduction and Overview

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The electricity industry, one of the major sources of stationary CO_2 emissions, is an important target for climate policies in the European Union (EU). Even though climate policies' main aim is to reduce emissions by changing the behavior of market agents in the long term, the policies influence the behavior of electricity producers, and thus emissions, in the short term as well.

Electricity production is subject to some distinct technical features that must be adhered to: most notably, the requirement of an instant balance between demand and supply, and the inflexibility of power plants because of start-up costs and constraints. Hence, the technical features of power plants may influence the market and the impact of policy measures in the short term.

The focus of my thesis lies in the interface of climate policies and the technical features of power markets; more specifically, how the inflexibility of power plants influences the outcomes and costs of climate policies in the short term.

Climate policies in the EU electricity industry

The EU has ambitious goals for the reduction of greenhouse gas (GHG) emissions. Under the Kyoto Protocol, the EU has committed to reduce GHG emissions compared with their 1990 levels by 8% during 2008–2012 (EC, 2002) and a stated goal is to reduce emissions by 20% by 2020 (COM, 2007). However, emissions are continuously measured against short-term, intermediate targets in order to measure the progress.

Climate policy measures directed towards the electricity industry take two distinctly different strands. First, emissions are made more expensive by introducing a cost on CO_2, with the aim of reducing the use of fossil fuels. In 2005, the EU Emission Trading Scheme (ETS) introduced tradable permits for CO_2 emissions from selected industries, of which emissions from the electricity and heat industry comprise more than half of the EU ETS market (EC, 2003). Permit trading under the EU ETS is set to be an important policy measure to reach the Kyoto commitments in 2008–2012. Second, another policy aim is to crowd out fossil fuels by subsidizing renewable energy sources: an objective has been set that 21% of electricity production should stem from renewable energy sources by 2010 (EC, 2001).[1]

Nevertheless, both kinds of policies affect *all* power producers through their market interaction, not only those that are targeted directly. Moreover, climate policies influence the behavior of producers even in the *short run*: the CO_2 cost changes the cost structure of existing fossil-fueled producers at once, while production from renewables influences both the level and the variability of power prices. Therefore, by altering the basis for market interaction, the policy measures influence the patterns of production and the emissions of each individual producer. These short-term impacts determine whether and at what cost the short-term commitments are kept.

Climate policies in economic analyses

The policy design of climate policies is a result of political compromises and the final result may resemble a patchwork of contradicting measures. Analyses based on numerical models are therefore useful to get a grip of the finicky details of policy design (see Weyant (1999) or de la Chesnaye and Weyant (2006) for a general overview of recent developments in the numerical analysis of climate policies; Amundsen et al. (1999), Hauch (2003), Hindsberger et al. (2003) and Unger and Ahlgren (2005) are examples of numerical analyses of climate policies in the Nordic power market). Yet, most analyses are based on market models that omit many of the technical

[1] Other goals, such as the support of domestic industries and regional development or an increase in the share of domestic fuel, are less pronounced, but nevertheless evident in the variety of renewable support schemes in the EU.

features of power plants. Some of these technical features may influence the way the markets work, and thereby alter the policy outcomes from what is expected. For instance, the reduction in emissions may be higher or lower than expected or, in a cap-and-trade system, the costs of reaching a given goal may be under- or overestimated. Hence, taking these technical features into account could also have implications for policy recommendations.

Seeing that these features are not well known among economists, let me first address some of the technicalities of power generation.[2]

Start-up costs in fossil-fueled power plants

One of the key features of the electricity system is the requirement for an immediate balance between production and consumption at every instant 'if the lights are to be kept on'. At the same time, demand varies from hour-to-hour (or even second-to-second), as illustrated in figure 1. Production in power plants must correspondingly vary to meet demand at every instant. However, most power production technologies are not perfectly flexible and thus cannot adjust the level of production instantly. The focus of my thesis is on the effects of the start-up costs and other short-term constraints prevalent in conventional, fossil-fueled thermal power plants.[3,4]

In addition to the short-term operational marginal costs of producing a kilowatt-

[2] Since the starting point of the papers is the impact of a technical feature – in the form of start-up costs – it is necessary to explain the technicalities in some detail. As the essays in the thesis seek to be self-contained, some overlap is unavoidable.

[3] The term *thermal power plants* is used throughout this thesis to denote conventional fossil-fueled power plants, although in a strict sense, nuclear and biomass-fired power plants are also *thermal*.

[4] Electricity can be produced with a variety of fuels and technologies with different characteristics: hydropower, nuclear power, fossil fuels (coal, natural gas and oil) and wind power, to name just a few. Because the focus of this thesis is on start-up costs prevalent in the conventional, fossil-fueled thermal power plants common in Europe, the description concentrates on the properties of these plants. These power plants are also the only option for new large-scale generation in many countries: hydropower development, for instance, is clearly limited by the availability of suitable watercourses.

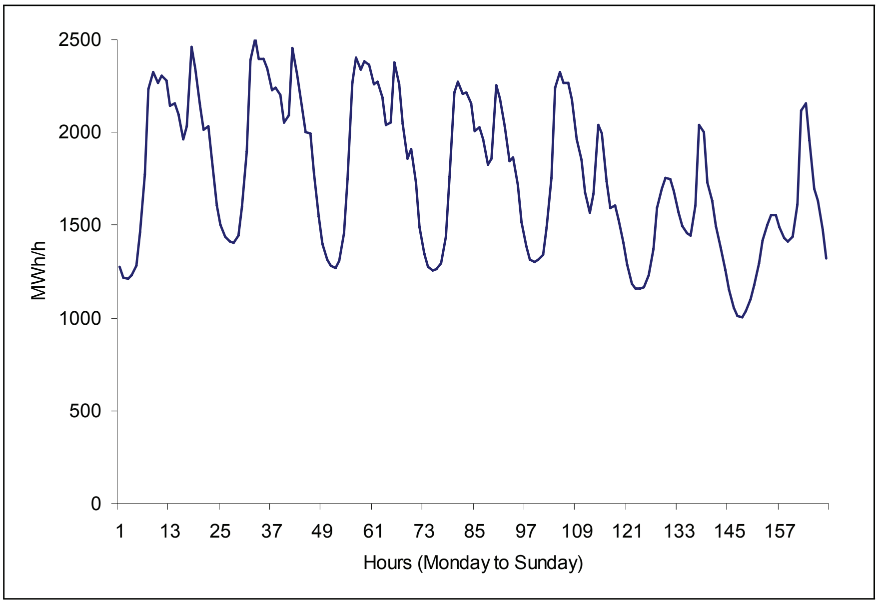

Figure 1: Hourly power demand throughout a typical week.
Source: www.energinet.dk

hour (fuel costs, production taxes, and operation and maintenance costs), the starting and stopping of a plant cause additional costs, even in the short term (i.e., apart from the long-term issues pertaining to investments, mothballing and scrapping a plant), see Wood and Wollenberg (1996). The start-up costs consist of additional fuel costs and indirect costs. The *indirect* start-up costs are related to the increased wear and tear that reduce the lifetime of the plant. The *fuel costs* reflect the extra fuel use during the start-up phase. The fuel use varies with the temperature of the boiler and depends on how long the unit has been shut down. If the unit has been turned off only recently (a few hours ago) and the temperature of the boiler is still high, the necessary fuel use is lower and the cost of starting the unit is lower than when the unit has been off for a longer period of time.

Table 1 illustrates the significance of start-up costs compared with operational marginal costs in continuous production mode in some typical plants: namely, a medium-aged coal-fired plant, a relatively new natural gas-fired plant and a gas

	Coal	Natural gas	Gas turbine
Operational marginal cost (DKK/MWh)	147	206	892
Start-up: fuel cost of cold start (DKK/start)	55 600	30 000	4 400
Start-up: indirect cost (DKK/start)	453 400	294 000	18 800

Table 1: Marginal and start-up costs of sample power plants (the author's calculations)

turbine. The coal-fired plant is cheaper in continuous operation than the natural gas-fired plant, while the start-up costs of the natural gas-fired plant are lower than those of the coal-fired plant. Merely the fuel cost of a start-up in a coal-fired plant is equivalent to the cost of producing at maximum production level for about one hour. When the indirect costs are taken into account, the cost of a start-up in a coal-fired plant corresponds to about eight hours of production costs. For the gas-fired plant, the fuel cost of a start-up corresponds to production cost in $\frac{1}{2}$ hour and the total start-up cost, including indirect costs, to four hours of production costs. The gas turbine has much lower start-up costs than the other plants, but the marginal production cost is considerably higher. Therefore, the gas turbine is typically used for relieving shortage situations that last only a few hours and not for prolonged production.

When power plants have costs related to starting, the production decision becomes an intertemporal decision, and the economists' conventional 'price vs. marginal cost'–rule is not sufficient for predicting the short-term production in thermal power plants. On the one hand, an idle plant will not start if prices are expected to be higher than the short-term marginal costs only a short period. On the other hand, if a plant is already producing, it will not stop for a short period of low prices – it would rather make a short-term loss in order to avoid shutdown.

In a flexible, competitive market, power plants produce according to marginal costs: the cheapest (most efficient) plants are used first, and more expensive plants are called for only when more capacity is required. When start-up costs are present, it is not necessarily the producers with the lowest marginal costs that produce at every instant: due to the trade-off between continuous production and a shutdown that implies a start-up later, more expensive plants (in terms of operational marginal costs) may produce nonstop and replace cheaper plants.

Inflexibility may enhance or counteract the effect of climate policies

Climate policy measures influence both the marginal and the start-up costs of producers and the price pattern in the power market in the short term. The presence of start-up costs is therefore likely to influence both the production decision of an individual power plant and the interaction between producers in a market.

The two strands of climate policies that are employed by the EU – a CO_2 cost and the subsidization of renewables – influence fossil-fueled plants in different ways. The CO_2 cost has a *direct* impact on conventional thermal power plants: a tax on CO_2 emissions will increase both the marginal production costs and the start-up costs of a power producer using fossil fuels. However, it will also change the relative costs of different producers and hence alter the basis for market interaction (merit order of plants). The start-up costs may either enhance or counteract emission reductions in the short term.

Subsidies to renewables influence fossil-fueled power plants *indirectly* through the electricity market and the price mechanism. Wind power – one of the preferred sources of renewables in many countries – is a variable source of power, as it can only produce when the wind is blowing (some authors even call wind power an 'intermittent power source'). This variation must be compensated for by other (thermal) power plants. If these power plants cannot adjust their level of production quickly, the variation in wind power production will be transmitted to power prices. Thus, flexibility of the entire power system is important for how easy it is to accommodate wind power. Although wind power is flexible within the limits of the available wind, this flexibility is not necessarily promoted by the subsidy schemes. Different subsidy schemes have different impacts on wind power producers and can either reinforce or alleviate the adverse properties of wind power. Again, because of the start-up costs, the effects of subsidies may be different from that predicted by standard models, and the cost of emission reduction may be higher than expected.

A sphere neglected by economists

Electrical engineers, being responsible for operating the power systems, have of course been concerned with the impact of start-up costs.[5] However, their focus has been on the technicalities of 'keeping the lights on' – typically finding algorithms that are suitable for solving the complex operation of power systems. Policy analysis has not been their primary concern. Economists, on the other hand, have disregarded these technical features and assumed the continuous, smooth functions common in economic analysis. This is justified when analyzing long-term trends, where a decade comprises the unit of time, with large (global or regional) models. However, policy impacts in the short term or in a limited geographical area may be substantial because of short-term inflexibility.

To the best of my knowledge, there are only two studies in the field of economics that take into account start-up costs. First, in an econometric analysis of potential market power in the PJM market, Mansur (2003) included start-up costs. He found that start-up costs may explain part of the mark-up (in excess of marginal costs) in producers' bids to the market. Although climate policy issues are not the focus of his attention, Mansur's empirical findings suggest that short-term inflexibilities and start-up costs substantially alter the operating decisions of power plants. This

[5] This field is categorized by the term *unit commitment*; see Sen and Kothari (1998) or Sheble and Fahd (1994) for an overview.

has implications for market interactions and policy outcomes. Second, Tseng and Barz (2002) use real options theory to value generation assets and find that failure to take into account the short-term constraints may lead to overvaluation of power plants.

An outline of the thesis

The contribution of my thesis is to include a technical feature previously neglected in economic models – start-up costs in thermal power plants – and to apply the new model in climate policy analyses.

The point of departure is the actual policies implemented in the EU. The numerical models are calibrated with Danish data. Denmark provides an interesting and relevant example to these types of policy concerns. First, the Danish power system is currently dominated by thermal (coal and gas-fired) power plants where start-up costs are substantial. At the same time, Denmark is at the forefront of climate policy, introducing a domestic permit trading system for CO_2 emissions from electricity production as early as 2001. Other support schemes have promoted wind power investment, with wind power production in Denmark covering about 20% of power demand in 2005. Further, according to the latest policy documents, a stated goal is to double wind power capacity by 2025 (TRM, 2007). Combined with other measures, this suggests that half of total electricity demand in Denmark will be met by wind power. Nevertheless, even though Denmark is at the forefront of these developments, it is not unique, with other EU countries, most notably Germany, Spain and the United Kingdom having ambitious goals of increasing their wind power capacity.

The overarching feature of all of the essays in this thesis is the short-term impacts of climate policies when the start-up costs in thermal power plants are taken into account. Essay 1 analyzes how the behavior of a *single* producer is influenced by climate policies, by both the policies directed towards him and by the policies that influence him through the market. An important insight is that the effects on total emissions remain ambiguous when only one firm is considered. Critically, the production pattern of an individual producer is determined in interaction with other producers in the market. Therefore, the following two essays study the effect of climate policies in a *market* – in other words, the aggregated effect on emissions and costs when the changes in the production patterns of all producers are taken into account. Essay 2 analyzes the importance of the flexibility of power plants in the presence of CO_2 cost, while Essay 3 analyzes the impact of different subsidy schemes on wind power in an inflexible market context. A numerical market model that takes the short-term start-up constraints into account is developed to this end.

The numerical model (developed for and applied in Essays 2 and 3 of the thesis) is a mixed integer linear programming optimization model that simulates the Danish power market in detail. Denmark is part of the Nordic power exchange Nord Pool, where the market is cleared simultaneously for each of the 24 hours of the following day.[6] Therefore, hourly time resolution and discrete time framework are appropriate. The distinct weekly pattern in power demand is likely to form the basis for producers' short-term planning. The numerical model therefore assumes simultaneous optimization over a week in the context of an infinite number of weeks, that is, a week is followed by an identical week *ad infinitum*.[7] Given that the weekly demand pattern is identical for all weeks, it can be shown that optimization over a week solves the full intertemporal optimization problem.

The detailed time resolution required for the proper modeling of start-up costs, combined with the computationally demanding integer modeling, is hardly feasible

[6] Real-time market, that operates close to the actual hour of operation, ensures that deviations between the planned and actual production and demand are balanced.

[7] This is different from Nord Pool's simultaneous consideration of 24 hours.

with long-term models. Adding a new feature that improves the realism of the model points out areas where the climate policy outcome may differ from the expectations originating from more simplistic models. Therefore, the essays in my thesis complement traditional policy analyses of power markets in economics (such as Amundsen et al. (1999), Hauch (2003), Halseth (1998) and Johnsen (1998) in the Nordic power market) by indicating how it might be necessary to modify the results of these long-term studies.

A more detailed outline of each of the essays follows.

Essay 1: The Impact of Climate Policies on the Operation of a Thermal Power Plant

This essay analyzes how the optimal production decision of a *single* fossil-fueled power producer is influenced by climate policies. It is first shown that the threshold prices for starting and stopping deviate from the producer's marginal costs: the starting threshold is higher than the marginal costs and the stopping threshold is lower.

Moreover, climate policies change the threshold prices: higher power price variation (as a result of the expansion of wind power capacity) increases the starting threshold and reduces the stopping (shutdown) threshold, relative to the marginal costs. A higher starting threshold means that a higher price is needed before an idle plant is started. On the other hand, the price must drop to a lower level before an operating plant is shut down. Put differently, the thermal power producer becomes less flexible – whatever state the producer is currently in, a larger price change is needed before it is optimal to switch to the other state. However, the effect on emissions is ambiguous, because it is not clear whether the plant will produce more or have longer idle periods.

A price on CO_2 (as a result of an emission trading system) increases both the marginal cost and the start-up cost of a power plant, as well as the expected power price. The numerical results show that for the marginal producer, the impact of the start-up cost on the producer's operation decision diminishes and the producer becomes more flexible. As both the starting and stopping thresholds are closer to the marginal cost, the operation decision resembles more the conventional 'price vs. marginal cost' rule. This implies lower emissions.

However, if the CO_2 cost is coupled with higher power price variation due to more wind power, the positive effects may be reversed as the two policies have opposing effects. Which effect dominates depends on the parameter values. Targeting the externality directly yields best results, while use of several policy measures at the same time may lead to undesired effects.

One implication of the analysis is that the technicalities of a power system (especially the technological structure) matter for policy outcomes. A policy design that fails to take into account the characteristics of the power system may lead to poor outcomes – either higher emissions or a higher quota price than expected.

Essay 2: Carbon Costs in Power Markets: The Importance of the Flexibility of Power Plants

The analysis in Essay 1 concludes that a CO_2 cost increases the flexibility of the producer; yet, the impact on *total* emissions is not clear-cut, since increased flexibility of a single producer may lead to either higher or lower production for a particular producer. Moreover, as the starting process itself also causes CO_2 emissions, the total emissions depend on the total number of starts and stops during a given period.

This essay takes the analysis of the previous essay a step further by modeling the start and stop costs in a *market*, thereby enabling study of the interaction of different producers in a market. The focus here is on how emissions for a given level of a CO_2 cost depend upon the flexibility of the power system as a whole.

The results suggest that effectiveness (in terms of the reduction in emission achieved) of a given level of CO_2 cost indeed depends on the flexibility of the power system. A lack of flexibility due to the start-up costs may either facilitate or counteract emission reductions in the short term. For some CO_2 cost levels, an inflexible system yields a higher reduction in CO_2 emissions than a flexible system – inflexibility reinforces the climate policy. For other CO_2 cost levels, however, inflexibility counteracts the climate policy: emissions are higher in the inflexible system. Hence, when assessing the effect of CO_2 pricing on emissions from a power system, it is highly relevant to take flexibility into account.

Essay 3: Subsidies to Renewable Energy in Inflexible Power Markets

This essay analyzes the other strand of EU climate policies – subsidies to renewables – in an inflexible market context. Building further on the market model developed in Essay 2, wind power production is included endogenously in the market interaction and different subsidy schemes to wind power are introduced.

Currently, there is a multitude of subsidy schemes to wind power in the EU. While the focus of many of the studies analyzing different support schemes to renewables (e.g., Menanteau et al., 2003) has mainly been the investment efficiency of support policies, the design of the subsidy scheme is also important for the wind power producer's short-term production incentives. The focus of this essay is on how different subsidy schemes to renewables – a lump-sum investment subsidy, a production subsidy as a mark-up on market price and a fixed price – influence short-term production in wind power and the interaction between wind power and thermal power plants.

An investment subsidy (a lump-sum subsidy in terms of the production incentives) does not distort the price signals in the market. If market prices reflect the shadow prices of start-ups and shutdowns in thermal power plants, both the wind power producer and the thermal power producers would vary production in order to accommodate variation in demand. Since a wind power producer is perfectly flexible within the limits of available capacity, it is sometimes profitable to reduce wind power production in order to avoid the shutdown of a thermal unit. Hence, the investment subsidy gives the optimal solution for wind power production from the point of view of the overall power system.

When the production subsidy is designed as a mark-up on the market price, the market signals are distorted, and wind power production is higher than optimal. Thus, investment and production subsidies are not equivalent in the short term.

A fixed price decouples the incentives to wind power from any market signals, and wind power always produces at its maximum available level. With low demand, thermal power plants are forced to stop in order to maintain balance in the market. This increases the total production costs of the power system considerably, compared to investment subsidy and production subsidy.

The main conclusion is that flexibility is crucial to the cost of wind power accommodation in the market, and thus the efficiency of wind power as a measure to reduce emissions. While the investment subsidy is shown to be unambiguously superior to other types of subsidies, the adverse effects of the other subsidies depend on the degree of flexibility of the existing power system. If the power system consists of thermal power plants that are inflexible, subsidies to wind power should strive to increase the flexibility of the market by passing market signals to wind power producers. Subsidies that conceal market signals from wind power producers considerably increase the total costs of emission reductions. Hence, an inflexible power system should aim at introducing optimal subsidies (as a lump sum) instead of production subsidies or a fixed price. An ill-designed subsidy scheme to renewables, combined with an inflexible system, may contribute to excessive costs of emission reduction.

Flexibility can also be achieved by technical measures (increasing trade possibilities or demand response) or economic incentives. However, these measures to increase flexibility require further investments that add to costs, in addition to the subsidies to wind power. An economically sound subsidy design that does not distort the production decision of wind power and promotes flexibility in wind power production may be the cheapest way of integrating wind power.

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Essay 1

The Impact of Climate Policies on the Operation of a Thermal Power Plant

The Impact of Climate Policies on the Operation of a Thermal Power Plant

*Orvika Rosnes**

Climate policy measures aimed at power markets influence the cost structure of producers and price patterns, and are therefore likely to influence the production decision of power plants, even in the short run. When power plants have costs related to starting and stopping, decisions on short-term production are intertemporal, and the conventional 'price vs. marginal cost' rule is not sufficient to predict production in thermal power plants. This paper analyzes how the optimal production decision is influenced by climate policies: namely, CO_2 trading mechanisms, the expansion of renewables and the interaction between these policies.

The main result is that higher power price variation (as a result of increased wind power production) makes the thermal power producer less flexible, but the effect on emissions is ambiguous. A CO_2 cost (as a result of an emission trading system) increases the flexibility of the producer and the operation decision resembles the conventional 'price vs. marginal cost' rule more. This implies lower emissions. However, when the CO_2 price is coupled with higher power price variation, the positive effects may be reversed since the two policies have opposing effects.

1. INTRODUCTION

Climate policies directed towards the electricity industry aim to reduce CO_2 emissions by reducing the use of fossil fuels. Considering the long-term nature of the climate change, long-term trends have been the natural focus of attention for most economic studies (see e.g., Weyant (1999), Springer (2003) and de la Chesnaye and Weyant (2006) for an overview of different numerical models and their results). However, climate policies also influence electricity markets in

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the short term: by changing market prices and the costs of producers, the policies influence not only long-term (investment and closure) decisions, but also the short-term production decision – whether to produce today (or even in a given hour) or not.

Climate policy measures aimed at the electricity industry in the European Union (EU) follow two distinctly different strands and influence fossil-fuelled plants in different ways. First, the cost of CO_2 emissions is increased through an emissions trading system (EC, 2003). By increasing the cost of fossil fuels, the CO_2 cost has a direct impact on traditional thermal power plants.[1] Higher costs are likely to transmit into higher prices and, unless leakages occur, producers with low emissions replace producers with high emissions (Amundsen et al., 1999, Hauch, 2003). Second, fossil fuels are meant to be crowded out through the subsidization of renewables (EC, 2001). Renewables will influence the fossil-fuelled producer only indirectly, through the electricity market and the price mechanism. Boosting renewables' capacity (wind power in many cases) through subsidies implies a lower price level: many renewable technologies have low marginal operating costs and will therefore replace conventional power plants, thus reducing the marginal costs of electricity production and hence the market price (Hindsberger et al., 2003; Unger and Ahlgren, 2005; Morthorst, 2006). However, wind power is a variable energy source: it can only be produced when there is wind and, for any given level of wind power capacity, the actual level of production is uncertain.[2] Since electricity cannot be stored, the variation in wind power production will be transmitted to power prices if production in other plants cannot be adjusted quickly and easily.[3,4]

In economic analyses, it is common to assume that power plants are perfectly flexible: power plants can start production instantly and without incurring any extra cost. Nonetheless, there are costs related to starting and stopping a thermal power plant even in the short-term (i.e., apart from the long-term issues pertaining to investments, mothballing and scrapping a plant), see Wood and Wollenberg (1996). On the one hand, an idle plant will not necessarily start if prices are expected to be higher than the short-term marginal costs for a short period of time. On the other hand, if a plant is already producing, it will not stop during a

1. The term *thermal power plants* is used throughout this paper to denote conventional fossil-fuelled power plants, although in the strict sense, nuclear and biomass-fired power plants are also thermal.

2. Some studies even refer to wind power as an 'intermittent' power source. Similarly, solar and wave power are variable, while other renewable technologies (e.g., biomass-fuelled CHP) are more similar to conventional power plants or are flexible (hydropower).

3. The consequences depend, of course, on the flexibility of the entire power system: a hydropower system is more flexible than a thermal power system and can easily adjust production so as to accommodate wind power. Similarly, the availability of sufficient transmission lines facilitates the accommodation of wind power, while large wind parks in isolated areas pose greater problems. Finally, the wind power capacity, relative to the total market size, is important for these consequences.

4. The effect on prices also depends on power market design, e.g., spot (day-ahead) market prices will be less affected than prices in the real-time balancing market (Morthorst, 2003). Nevertheless, I ignore these technicalities here and focus on prices in general.

short period of low prices. The production decision is then an intertemporal decision, and the conventional 'price vs. marginal cost' rule is not sufficient to predict production in thermal power plants.

Moreover, due to the intertemporal decision in the presence of start and stop costs, the impact of climate policies is not clear-cut: the total production and emissions of a thermal power plant may be either lower or higher than predicted by the conventional 'price vs. marginal cost' rule. In addition, the start-up itself contributes to higher emissions (due to higher fuel use) than a smoother mode of production. In a cap-and-trade system, higher emissions imply a higher quota price, if the total cap is to be met.

This paper fills a gap in the literature by incorporating start and stop costs in an analysis of climate policies. Mansur (2003) finds, in an econometric study of potential market power in the Pennsylvania, New Jersey and Maryland electricity market, that the start-up costs, together with other short-term intertemporal constraints, explain a large part of the mark-up (i.e., the portion in excess of marginal costs) in power producers' bids to the market. Mansur's empirical findings suggest that the start-up costs substantially alter the operation decisions of power plants. This has implications for the market and, hence, policy outcomes. Tseng and Barz (2002) use real options theory for valuation of generation assets and find that failure to take into account the short-term constraints may lead to the overvaluation of power plants. Although the remaining economic literature (excluding the aforementioned papers by Mansur and Tseng and Barz) has ignored the issues related to the intertemporal constraints of power plants, these issues have been extensively studied in electrical engineering literature (under the term *unit commitment*); see e.g., Sen and Kothari (1998) or Sheble and Fahd (1994) for an overview. This strand of literature has, however, focused on the technicalities of modeling, being concerned with finding suitable algorithms for the actual operation of large power systems. Climate policy issues have not been at the center of attention.

This paper analyzes how the optimal production decision of a fossil-fuelled power producer is influenced by higher uncertainty about the power price (as a result of more renewables), higher costs of fossil fuels (as a result of CO_2 trading mechanisms) and the interaction of these effects (as a result of the simultaneous use of the two policy measures). This is analyzed in a numerical model, using data from Denmark as an illustration. The focus is on a single producer's operation decisions in the very short term, given its costs and exogenous prices.

2. THE MODEL

Dixit's (1989) seminal paper on entry and exit decisions under uncertainty has become a workhorse in investment analyses. Employing the analogy between real and financial options, the entry and exit decisions are regarded as call options. Investment and abandonment costs lead to hysteresis in investments in an uncertain environment. Dixit and Pindyck (1994) present extensions to the model. Here, a similar framework is applied to a *short-term production decision*. Since prices in the Nordic power pool Nord Pool are cited hourly, a discrete time framework is appropriate for the problem at hand.

Consider a firm that can produce q_t units of output in each time period t. Assume that this is an on/off technology, producing either at its maximum capacity level q^{max} or not at all: $q_t = q^{max}$ or $q_t = 0$.[5] With an exogenous output price p_t and short-term marginal production costs c, the firm can earn $(p_t - c)q_t$ in each period. The output price is a continuous variable with state space $p_t \in [0, \infty)$. However, in addition to the short-term marginal costs, the producer faces a start-up cost C_{start} if he did not produce in the previous period and starts to produce in this period, and a shut-down cost C_{stop} if he stops production. The start-up and shut-down costs are sunk costs.

Thus, the profit for each period depends on the two state variables *price* and the *operational status of the firm* (on/off) that are observed at the beginning of the period. The 'status variable' d_t is a binary variable, $d_t \in \{0,1\}$ ($d_t = 0$ if the plant is 'off', i.e., not producing; $d_t = 1$ if 'on', i.e., producing). Development of state variables over time is determined by state transition functions

$$d_t = h(d_{t-1}, x_{t-1}) \tag{1}$$

and

$$p_t = g(p_{t-1}, \varepsilon_t) \tag{2}$$

where d_t and p_t indicate the state variables at the beginning of period t and ε is a random variable.

When deciding whether to remain in the current state (continue to produce/remain idle) or change the state (start/stop), the producer considers not only the earnings in this period, but also the effect of the decision on future profits in all $t = 1, ..., \infty$. The action variable x_t is a binary variable, with an action space $x_t \in \{0,1\}$ ($x_t = 0$ if 'not operate', $x_t = 1$ if 'operate'). It follows from the assumption of on/off technology that $x_t = 1$ implies $q_t = q^{max}$ and $x_t = 0$ implies $q_t = 0$.

The total profit π_t in period t depends both on the state variables p_t and d_t at the beginning of the period and on the action x_t in period t:

$$\pi_t(p_t, d_t, x_t) = [(p_t - c)q_t]\, x_t - C_{start}(1 - d_t)\, x_t - C_{stop}(1 - x_t)\, d_t \tag{3}$$

Thus, there are four different outcomes for π_t:

5. Since the focus of this paper is on the effect of start and stop costs, I focus on the operate/not operate decision and disregard the possibility of choosing different levels of production. The analysis can be extended to the choice of production level in the space $q_t \in [q^{min}, q^{max}]$. This, among other extensions, is treated in Rosnes (2005).

$$\pi_t(p_t, d_t, x_t) = \begin{cases} (p_t - c)q_t & \text{if } d_t = 1 \text{ and } x_t = 1 \\ -C_{stop} & \text{if } d_t = 1 \text{ and } x_t = 0 \\ (p_t - c)q_t - C_{start} & \text{if } d_t = 0 \text{ and } x_t = 1 \\ 0 & \text{if } d_t = 0 \text{ and } x_t = 0 \end{cases} \quad (4)$$

The value function $F(p_t, d_t)$ expresses the maximum achievable payoff throughout the whole planning horizon, given the present states:

$$F(p_t, d_t) = \max_{x_t} \{\pi_t(p_t, d_t, x_t) + \delta E[F(g(p_t, \varepsilon_{t+1}), h(d_t, x_t))]\} \quad (5)$$

where δ is the discount factor and E is the expectation operator. Equation (5) is the Bellman equation and expresses the trade-off between the immediate payoff, $\pi_t(p_t, d_t, x_t)$, and the expected future payoffs, $\delta E[F(p_{t+1}, d_{t+1})]$, that an optimizing agent must balance.

2.1 Optimal Operation Decisions

Active Firm

If the active firm ($d_t = 1$) continues to produce ($x_t = 1$), it earns profit $\pi_t = (p_t - c)q_t$ in this period. Furthermore, it retains the possibility of producing and earning profits in the future. If it stops, it incurs the stopping cost of C_{stop} in this period. However, it has the possibility to start again later, but then incurring the cost C_{start}. By inserting (4) into (5), the value function of the active firm becomes

$$F(p_t, 1) = \max \{-C_{stop} + \delta E[F(p_{t+1}, 0)]; (p_t - c)q_t + \delta E[F(p_{t+1}, 1)]\} \quad (6)$$

The first term on the right-hand side (RHS) is the termination payoff, i.e., what the firm gets if it stops production now. The second term on the RHS is the continuation payoff, i.e., what the firm gets if it continues to produce.

Idle Firm

An idle firm ($d_t = 0$) has the choice of staying idle or starting to produce in each period. If it continues to stay idle ($x_t = 0$), profit in this period will be zero. If it starts to produce (i.e., stops being idle; $x_t = 1$), it incurs the start-up cost C_{start} in this period, but also earns $(p_t - c)q_t$ and has the possibility of earning profits in the future. The Bellman equation for an idle firm is thus (by inserting (4) into (5))

$$F(p_t, 0) = \max \{[(p_t - c)q_t - C_{start}] + \delta E[F(p_{t+1}, 1)]; \delta E[F(p_{t+1}, 0)]\} \quad (7)$$

The first term on the RHS is the termination value, consisting of the pay-off in this period and the expected future payoff. The second term is the continuation value of staying idle.

Threshold Prices for Starting and Stopping

The firm's objective is to maximize the flow of profits over time, $t = 1, ..., \infty$. The optimal action is the one that balances the immediate payoff and the expected flow of future payoffs. Note that (6) and (7) assume that the future decisions are going to be optimal and that the future value of the firm is contingent on the state variables in the current period, p_t and d_t.

The solution to this pair of dynamic optimization problems (6) and (7) is *two threshold prices* for changing the operational status: p_{start} is the threshold for an idle firm to start operation, and p_{stop} is the threshold for an active firm to stop operation. Together these prices ($p_{stop} < p_{start}$) define three regions:

- In the interval $(0, p_{start})$ the idle firm continues to be idle.
- In the interval (p_{stop}, ∞) the active firm continues to produce.
- In the interval (p_{stop}, p_{start}) the firm continues in the current state (either idle or active).

The threshold prices p_{stop} and p_{start} depend, obviously, on the costs (c, C_{start}, C_{stop}) and size (q^{max}) of the plant, that is, on parameters related to the power plant technology and fuel costs, and on parameters of the transition function for price $g(p_t, \varepsilon_{t+1})$.

2.2 Flexibility of a Producer

The flexibility of a producer can be measured by the wedge, or difference, between the threshold prices: the smaller the wedge, the more flexible the producer. In other words, the smaller the difference between p_{stop} and p_{start}, the more likely it is that the producer will change his operational status because of a price change. For the perfectly flexible producer, $p_{stop} = p_{start} = c$. On the other hand, if the wedge between the starting and stopping thresholds is large, the producer is more likely to remain in the current operational status for a given price change.

However, it is not only the mere difference between the threshold prices that is important for the operation decision, but also the *relative difference* between the thresholds and the marginal cost. On one hand, an idle producer will not start if the price is just slightly higher than the short-term marginal cost. On the other hand, if he is already producing, the producer will not stop at once if the price falls below the marginal cost. *How much higher* than the marginal cost is the starting threshold and *how much lower* than the marginal cost is the stopping threshold are important considerations in the decision.

2.3 Climate Policies Change Threshold Prices

The threshold prices for starting and stopping of a plant p_{start} and p_{stop} depend on the costs of the plant (c, C_{start}, C_{stop}) and the expected future prices. Obviously, circumstances that influence these parameters (as tradable emission quotas or increased price variation) will also influence the threshold prices.

A considerable increase in wind power capacity is expected to increase power price variation. Higher price variation operates through the random variable ε in the state transition function for price (2). As can be seen from equations (6) and (7), higher price variation influences both the value of the active and of the idle firm: both the continuation value and termination value for both operational states are affected. Which of the effects dominates depends on the parameter values and the functional forms.

A higher CO_2 price will increase costs (both marginal costs and start and stop costs). The costs will affect both the value of being active and the value of being idle. C_{start} directly affects only the termination payoff of an idle firm. However, it also affects the active firm indirectly, through the expectation of future profits. Similarly, C_{stop} directly affects only the termination value of the active firm, but indirectly both the value of being active and being idle are affected.

The dynamic programming equations (6) and (7) lack a closed-form solution and must be solved numerically.[6] Therefore, I turn to a numerical example.

3. INPUT PARAMETERS IN THE NUMERICAL MODEL

In order to analyze the effect of climate policies on the production decision and the flexibility of a producer, the optimization problem consisting of equations (6) and (7) is solved numerically, by adapting the algorithms provided by Miranda and Fackler (2002). This section gives a brief overview of the input parameters used in the numerical model.

A ‘typical’ coal-fired power plant in Denmark is used as an illustration for how climate policies influence the production decision and flexibility of a producer. Denmark serves as a good example for possible developments in the EU in that prolonged support schemes have boosted the use of renewable energy in electricity production. Wind power now constitutes a sizable share of total electricity production capacity in Denmark, producing nearly 20% of total electricity in 2005 (23% of domestic electricity consumption). Even though Denmark is at the forefront of climate policy issues, the country is not unique: wind power is envisaged to be the main source of renewable energy in many European countries to fulfill the goal of 22% renewables in electricity production by 2010 (EC, 2001).

3.1 Parameters Related to the Power Plant

The start-up costs of an electricity generating unit vary with the temperature of the boiler and depend on the time the unit has been shut off. If it has been off for a long period of time, *cold start* costs will be incurred. Cold start costs comprise fuel costs for running the unit at maximum capacity for ½ hour (fuel

6. The solution methods in the continuous time framework are well known, see e.g., Dixit and Pindyck (1994).

oil, not coal, is usually used for start-up in coal-fired plants). If the unit has been turned off only recently, and the temperature of the boiler is still high, the cost of starting the unit is lower (this is known as *hot start* in industry jargon).[7]

Table 1 sums the assumptions about the parameter values and the resulting costs for the 'typical' modern power plant (with 400 MW capacity and 45% efficiency), assuming a coal price of 50 EUR/ton and a heavy fuel oil price of 203 EUR/ton. The national CO_2 tax (40 DKK/ton = 5.4 EUR/ton) applied to power producers in Denmark in 2000–2004 (before the EU Emission Trading System) is included in the base case.

Table 1. Assumptions about Power Plant Costs, Base Case (The Author's Calculations)

Marginal production cost (EUR/MWh)	22.1
Start-up cost, cold start (EUR/start)	8,662
Fuel cost of start-up (EUR/start)	7,984
CO_2 cost of start-up (EUR/start)	678
Stopping cost (EUR/stop)	0

In addition to the fuel costs, starting and stopping a power plant increases wear and tear on the plant, thus reducing its lifetime. Due to a lack of data, these costs are not included in the present analysis. The impact of these additional costs is, however, equivalent to increasing the value of the input parameter C_{start}, which is discussed in section 4.1 below.

There are no direct costs related to stopping, so in the following the focus is on the start-up cost only and C_{stop} is assumed to equal zero.

3.2 Parameters for the State Transition Function for Power Price

The future development of the exogenous market price p is uncertain: the price level may increase or decrease. The producer must take this uncertainty into account when deciding whether or not to produce now.

One of the simplest specifications of the state transition function for price (eq. 2), $p_t = g(p_{t-1}, \varepsilon_t)$, is a first-order autoregressive (AR(1)) relationship

$$p_{t+1} = \alpha + \beta p_t + \varepsilon_{t+1} \tag{8}$$

Uncertainty about the future price development is captured by the error term ε. Assuming $E(\varepsilon) = 0$, the expected price in period t+1 equals $p_{t+1} = \alpha + \beta p_t$. The variance of ε, σ^2, is the measure of variation in prices that is crucial in the analysis of climate policies below.

7. Hot start costs are usually modeled as an exponential function of cold start: $C_{hot} = C_{cold}\,(1 - e^{-(t/\tau)})$ where τ is the cooling constant measuring how quickly the boiler cools down, and t is the time the plant has been off (personal communication with Jens Pedersen, Energinet.dk, in June 2004).

Equation (8) was estimated, using the TSP software package (Hall and Cummins, 1999), with hourly price data (8,760 observations) for West Denmark in 2001.[8] The year 2001 was chosen as the most 'normal' year in the period for which price data are available (from July 1999 to present): there were allegations of the abuse of market power in 1999 and 2000, while 2002 and 2003 had very unusual hydrological conditions in Norway and Sweden that contributed to extremely high prices in the whole Nordic market (von der Fehr et al., 2005, Olsen et al., 2006). Although neither drought nor the abuse of market power can be ruled out in the future (moreover, these situations may well be considered normal in the future), these issues are not the focus of the present analysis. Nevertheless, the 'normal' situation does not imply that prices were necessarily low or that there were no price spikes in 2001.

The estimation results are (standard errors of the variables in parenthesis):

$$\underset{(\text{s.e.})}{p_{t+1}} = \underset{(1.2)}{6.61} + \underset{(0.007)}{0.73}\,p_t \tag{9}$$

The estimated variance of residuals is $\hat{\sigma}^2 = 49.0$. The residuals are normally distributed, even though the prices are not, and $R^2 = 0.54$. The average price in 2001 was 24.9 EUR/MWh.

The state transition function for price is symmetrical around the average price: if the price in one period is higher than the average price, the price is expected to fall over time. Similarly, if the price is below the average price, it is expected to increase over time. However, the advantage of the AR(1) relationship, compared to for instance a mean-reverting relationship $p_{t+1} = \gamma\,(p_t - p_{average}) + \varepsilon_{t+1}$, is that an AR(1) model puts more weight on the price in the previous period. In the short term, the price in the previous period is a better indication of the expected price in this period than deviation from the average. Typically, there is seasonal variation in power prices, with higher prices in winter than in summer. The power price in a given hour in January is not expected to fall only because it is higher than the annual average. Therefore, an AR(1) model is more appropriate than mean-reverting model.

An AR(1) model of power prices could, however, be regarded as an excessive simplification. There are pronounced daily and seasonal patterns in power price variation. Thus, a complete time series model would probably include many lags and differentiated series. However, rather than using a more elaborate time series model to predict prices, a producer forms his expectations of future prices based on *all* available information about circumstances that affect the market (temperature, demand and wind power forecasts, known outages of other power plants, etc.) and probably employs full-fledged market equilibrium models. Nevertheless, due to the stochastic elements, none of these forecasts are likely to be exact. Since the focus here is on how to react in the presence of stochastic ele-

8. The data is available online at www.energinet.dk.

ments *in the very short term*, when the realized price deviates from the expected price, I argue that the simple AR(1) provides sufficient insights.[9]

4. THRESHOLD PRICES IN THE BASE CASE

Using the parameter values shown in table 1 and estimation results in equation (9) as inputs, and assuming an infinite horizon, the pair of dynamic optimization problems (6) and (7) is solved numerically. The solution is two threshold prices for changing the operational status of the plant: p_{start} is the threshold for an idle firm to start operation, and p_{stop} is the threshold for an active firm to stop operation.

The solution for threshold prices in the base case is p_{start} = 27.9 EUR/MWh and p_{stop} = 15.3 EUR/MWh. In other words, only if the observed price is at least 27.9 EUR/MWh (5.8 EUR/MWh above marginal cost), is the expected flow of future profits high enough to make start-up profitable in this period (hour). On the other hand, the price can fall to 15.3 EUR/MWh before the immediate operating loss becomes large enough, when compared with expected future profits, to justify shutdown.

It is worth noting that in this example, the starting threshold is closer to the marginal cost (26% higher than the marginal cost) than the stopping threshold is (31% below the marginal cost). This implies that the producer is relatively 'quicker' to start an idle plant than to close an active plant. In other words, the power price must fall relatively more below the marginal cost before production stops, while the necessary increase in power price, in order to trigger a production start, is relatively smaller.

4.1 Sensitivity for the Magnitude of Start-up Costs

Table 2 reports how the results depend on the assumed parameter values for the start-up costs. *Cold start* refers to the case discussed above. *Semi-cold start* and *hot start* refer to cases with lower start-up costs. This can be interpreted as a situation when the unit has been off for shorter time and the temperature of the boiler is still relatively high.

Not surprisingly, the lower the start-up cost, the smaller the wedge between the two threshold prices. For the hot start, the starting threshold is only 4% higher than the marginal cost, and the stopping threshold is only 8% lower than the marginal cost. Note that in spite of assuming $C_{stop} = 0$, the stopping threshold p_{stop} does not remain constant for different levels of start-up costs. Moreover, in the hot start case, the plant is relatively 'quicker' to start that to stop – in other words, stopping is more difficult. The reason is that the stopping threshold captures the costs of future start-ups embodied in the termination value in equation (6).

9. Other specifications for the state transition function for price were attempted, particularly those including lags and 'seasonality' to reflect the daily variation pattern of prices. However, these specifications did not significantly improve the fit.

Table 2. Threshold Prices for Different Start-up Cost Levels, Base Case

	Cold start	Semi-cold start	Hot start
Assumptions:			
Start-up costs (EUR/start):	8,662	7,489	1,330
Fuel cost of start-up	7,984	6,903	1,226
CO_2 cost of start-up	678	586	104
Stopping cost	0	0	0
Marginal cost (EUR/MWh)	22.1	22.1	22.1
Results:			
Starting threshold (EUR/MWh)	27.9	27.3	23.0
Stopping threshold (EUR/MWh)	15.3	15.9	20.4

5. EFFECTS OF CLIMATE POLICIES

How will climate policies change the threshold prices and flexibility of the producer? In this section, the effects of higher uncertainty about power prices (as a result of more renewables), higher costs of fossil fuels (as a result of CO_2 trading system) and the interaction of these effects are analyzed.

5.1 Boost in Renewables Capacity

Increased Price Variation Reduces Flexibility

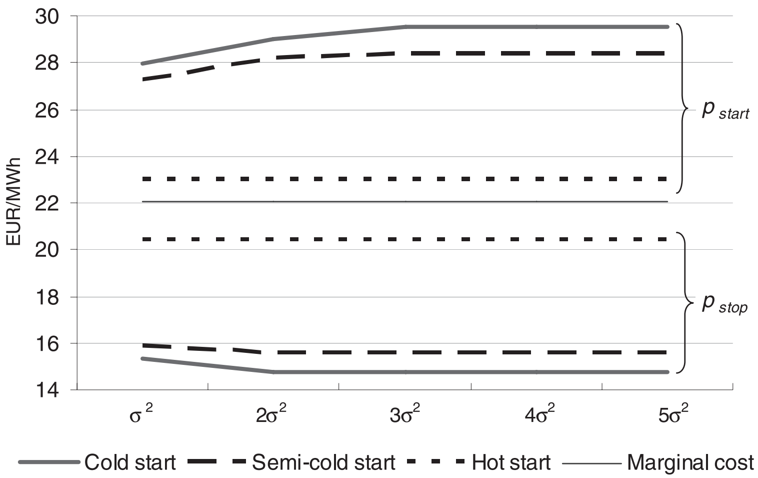
Higher price variation acts through increased variance σ^2 in the model.

In the Danish example, higher price variation increases the wedge between the threshold prices: p_{start} increases and p_{stop} decreases. This implies that a larger price change is necessary before the producer finds it profitable to change operational status of the plant.

Figure 1 shows the impact of increasing price variation on the starting and stopping thresholds. Figure 1 should be read as follows: the three lines in the upper half of the figure (above the marginal cost line) show the starting threshold p_{start} for three different parameter values of C_{start} (ref. table 2), while the three lines in the lower half show the stopping threshold p_{stop} for the same cases (the marginal cost is the same in all cases). Price variation (measured by σ^2) increases along the *x*-axis, that is, $2\sigma^2$ means that variance is doubled when compared with the base case.

The Bellman equations (6) and (7) are illuminating for understanding these effects. Higher price variation increases the value of being active for all price levels. Higher price variation means that future prices may increase to higher levels, implying a larger upside for future profits. The downside is limited, as the price cannot become negative. On the other hand, higher price variation also increases the value of being idle: postponing the start-up and waiting for more information in the next period(s) becomes more profitable. The numerical results indicate that for an active producer, the effect on the continuation value dominates:

Figure 1. Impact of Higher Price Uncertainty (Measured by σ²) on Threshold Prices for Different Cost Levels



the stopping threshold falls. For an idle producer, the effect of the continuation value dominates, increasing the threshold value for start-up. Note that in spite of assuming $C_{stop} = 0$, the stopping threshold p_{stop} does not remain constant, since the stopping threshold captures the effects (costs) of future start-ups.

However, the wedge between the threshold prices will not grow infinitely. With the present parameter values, the effect tapers off when the variation reaches about double its original value, and fades away altogether when the variation is quadrupled. Further increases in variance have almost no effect on the threshold prices. Moreover, the magnitude of the changes is relatively small: the wedge between the threshold values increases only by 1.6 EUR/MWh when the variance doubles.

Frequent Starts and Stops Retain Flexibility

The lower the start-up cost, the less the impact of higher price variation. In the hot start case, increased price variation has practically no effect on the threshold prices (figure 1). In the semi-cold start case, the results are similar to the cold start case (although the values are lower): an increase in price variation increases the wedge between the prices, but the effects quickly taper off. This implies a reinforcing effect: higher price variation has a larger impact on a firm that is initially relatively inflexible (i.e., has high start-up costs), thus making it even more inflexible. The impact on a firm with low start-up costs is less, and the flexible firm thus remains flexible.

Ambiguous Effect on Emissions

The effect of more renewables on total production and emissions from the coal-fired power plant is ambiguous. A higher starting threshold means that a higher price is needed for start-up. This implies that some start-ups are most likely avoided, which means less production and fewer emissions. On the other hand, the price must drop to a lower level before the plant is closed, which implies that some stops are also avoided. This may lead to greater production over time and more emissions from the plant.

Total emissions from the power plant depend on total production and on the number of start-ups during a certain time period ($t = 1,...,T$). Frequent starting and stopping itself contributes to higher emissions, since the starting process itself involves more fuel use than a continuous mode of operation.

All in all, we may conclude that the producer becomes less flexible. In other words, whatever state the producer is in, a larger price change is needed before it is optimal to switch to the other state. However, less flexibility is not unambiguously better for emission reduction.

5.2 Emission Trading System for CO_2

The EU Emission Trading System (ETS) that has operated since the beginning of 2005 has shown substantial price variation, and there is considerable uncertainty about the future price level of CO_2 (see e.g., the survey by Springer, 2003). Nevertheless, some price variation in the EU ETS market is arguably due to the lack of information in an infant market. It is reasonable to assume that as the market matures, the CO_2 price will be relatively stable in the short term and so known for the day-to-day operation of power plants. Therefore, the focus here is not on the uncertainty of the CO_2 price, but how a given CO_2 price level will influence the threshold prices.

In the simulations, the threshold prices for optimal starting and stopping have been calculated for CO_2 prices in the range of 0–40 EUR/ton CO_2 (40 EUR/ton CO_2 is the penalty level if the CO_2 quota is exceeded and thus acts as a price cap in the EU ETS).

A cost on CO_2 increases the parameter values for c and C_{start} (recall that $C_{stop} = 0$ by assumption) and the expected power price.[10] The relative increase in the expected power price is assumed to be equal to the relative increase in the marginal cost, implicitly assuming that the marginal power plants in the system

10. Introducing the CO_2 cost may also increase the power price variation. Since different plants are likely to determine the power price in different periods, and the relative costs of power plants change as a result of the CO_2 cost, the difference between prices in high demand and low demand periods may become larger. The impact of increased power price variation due to CO_2 cost is, however, similar to the impact of more renewables, discussed in section 5.1. The simultaneous impact of higher expected power price, higher power price variation and higher costs are discussed in section 5.3.

are similar to the one analyzed here.[11] The state transition function for power price is still symmetrical around average.

The costs and resulting threshold prices are reported in Table 3.

Table 3. Production Costs and Starting and Stopping Thresholds for Different CO_2 Cost Levels

CO_2 price	Costs:		Corresponding thresholds:	
	Start-up	Marginal	Starting	Stopping
EUR/ton	EUR/start	EUR/MWh	EUR/MWh	EUR/MWh
0	8,000	18.4	24.1	12.2
10	9,200	25.2	31.3	18.1
20	10,500	32.2	38.5	24.1
30	11,800	39.0	45.5	30.0
40	13,000	46.0	52.4	35.8

Higher CO_2 Cost Increases Flexibility

Figure 2 shows the starting and stopping thresholds, measured relative to the marginal cost, for different levels of CO_2 cost. It turns out that the CO_2 cost *increases* the flexibility of the producer: the higher the CO_2 cost level, the closer the starting and stopping thresholds are to the marginal cost and the smaller the wedge between the thresholds. In other words, the higher the CO_2 cost, the more the operation decision resembles the conventional 'price vs. marginal cost' decision.

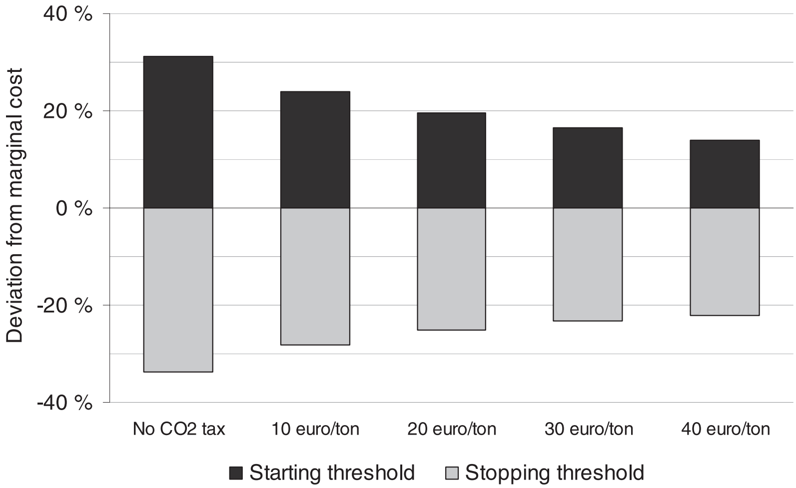
The reason for the increased flexibility is that due to different CO_2 content of the fuels, the CO_2 cost has an asymmetrical effect on the different cost elements. With no CO_2 cost, the start-up cost corresponds to more than an hour's production cost (i.e., marginal cost multiplied by production level), while for the CO_2 cost of 40 EUR/ton, the start-up cost corresponds to production cost in ¾ of an hour only. Hence, the impact of the fixed start-up cost on the operation decision becomes less important, the higher the CO_2 cost.

It is also worth noting that the change in the starting threshold is larger than that of the stopping threshold. With no CO_2 cost, the starting threshold is 31% (5.7 EUR/MWh) above the marginal cost and the stopping threshold is 34% (6.2 EUR/MWh) below the marginal cost (see figure 2 and table 3). In the case with CO_2 price 40 EUR/ton, the stopping threshold is only 22% below the marginal cost – making it 'easier' to stop. However, the starting threshold is only 14% higher than the marginal cost. Hence, it is also easier to start an idle plant: the required power price increase before starting is profitable is less than with no (or lower) CO_2 cost.

To sum up: the higher the CO_2 cost, the more flexible is the producer and the closer is the production decision to one based on pure marginal cost con-

11. This assumption does not imply, however, that they are in position to increase the market price through the abuse of market power.

Figure 2. Starting and Stopping Thresholds (Relative to Marginal Costs) for Different CO_2 Cost Levels



siderations. As long as the producer follows the marginal cost consideration, the implication is that there will be no 'unnecessary' production (that is, production when price is below the marginal cost). On the other hand, increased number of starts and stops could increase emissions. However, fuel use and hence emissions are lower with frequent starts and stops, as shown in section 4.1. Therefore, a CO_2 tax will most likely contribute to lower emissions even when start-up costs are accounted for.

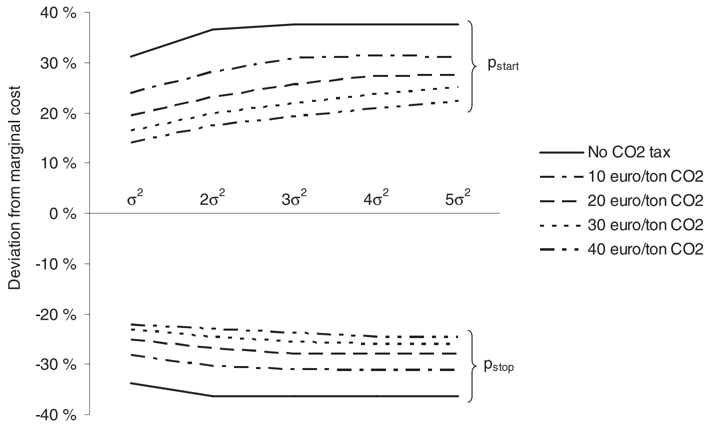
5.3 Simultaneous Effects of CO_2 Price and Renewables

While more renewables, by increasing the power price variation, reduce the flexibility of the producer, a CO_2 cost increases the flexibility of the producer. What is the effect of CO_2 price together with higher power price variation?

Figure 3 shows the impacts of higher price variation on threshold prices for different levels of the CO_2 cost. Similar to Figure 1, price variation (measured by σ^2) increases along the *x*-axis in Figure 3; however, the starting and stopping thresholds are shown here relative to marginal costs.

For a given level of CO_2 cost, increasing power price variation increases the wedge between the starting and stopping thresholds. This is similar to the findings in section 5.1. However, consistent with the findings in section 5.2, the relative wedge between the thresholds is less for the higher levels of CO_2 cost. Therefore, the combined effect of the two policy measures depends on the combination of the policies: low CO_2 cost combined with low power price variation may yield the same effect as high CO_2 cost combined with high power price variation.

Figure 3. Starting and Stopping Thresholds (Relative to Marginal Costs) for Different CO_2 Cost and Power Price Uncertainty Levels



Nevertheless, higher price variation due to wind power reduces the flexibility of the producer for every level of CO_2 cost – hence reversing the positive effects of introducing the CO_2 price. The common wisdom of choosing the policy measure that targets the externality directly is still valid here.

6. RELEVANCE

6.1 Price Expectations Are Important

Whether and how much impact start-up costs have on the optimal operation decision depends on the average power price level and assumed relationship for prices between different periods, in addition to power plant parameters.

If the prices, on average, are in the same range as the threshold values, prices are likely to hit the thresholds every now and then, causing the operational status of the plant to change. In this case, the start-up costs are important for the operation decision. If, however, the prices on average are far above (or below) the threshold values, the operational status seldom changes and the start-up costs matter less. The relevant price range is not constant either. Development of supply, demand and policy measures, including climate policy measures, influence power prices. In the current example, the average power price is 24.9 EUR/MWh – between the two threshold prices in the base case – indicating that the start-up costs are important for the operation decision.

The analysis above assumed that the relative increase in power price as a result of the CO_2 cost was equal to the relative increase in marginal cost of the power plant in focus here (that is, the plant in focus was the marginal one). This is plausible, but by no means the only possible outcome of introducing the CO_2 cost.

If the relative costs of power plants change after introduction of the CO_2 cost (as is intended), different power plants may determine the price in the market. Consequently, the power price increase may be less than assumed here and the expected price will be lower for each level of CO_2 cost.

Figure 4 shows the impact of the CO_2 cost on the starting and stopping thresholds of a more expensive power plant. (In order to illustrate the extreme case, the expected power price is kept constant at the base case level, while the costs of the plant increase.) The starting threshold increases, relative to the marginal cost, when the CO_2 cost increases. In the case with CO_2 price 40 EUR/ton, the power price must increase 42% above the marginal costs before it is profitable to start production. This implies that it becomes more difficult to start an idle plant. The reason is that as the power price is expected to fall, it is likely to make the start-up unprofitable. The stopping threshold increases, too, relative to the marginal cost when the CO_2 cost increases. With CO_2 price 40 EUR/ton, the starting threshold is barely below the marginal cost, making it 'easy' to stop. In other words, the higher the CO_2 price, the easier it is to stop an active plant and the harder it is to start an idle plant.

To put it differently: the lower the costs, the more likely it is that the producer is active (either remains active or, if idle, becomes active). On the other hand, the higher the costs, the more prone the producer is to be idle (to remain idle, or, if producing, to stop). If easier stopping and harder starting contribute to longer idle periods, the result is lower production and fewer emissions.

Introducing renewables in this case could reduce both starting and stopping thresholds, making it easier to start and more difficult to stop (Figure 5).

Figure 4. Starting and Stopping Thresholds (Relative to Marginal Costs) for Different CO_2 Cost Levels – Sensitivity with Lower Expected Power Price

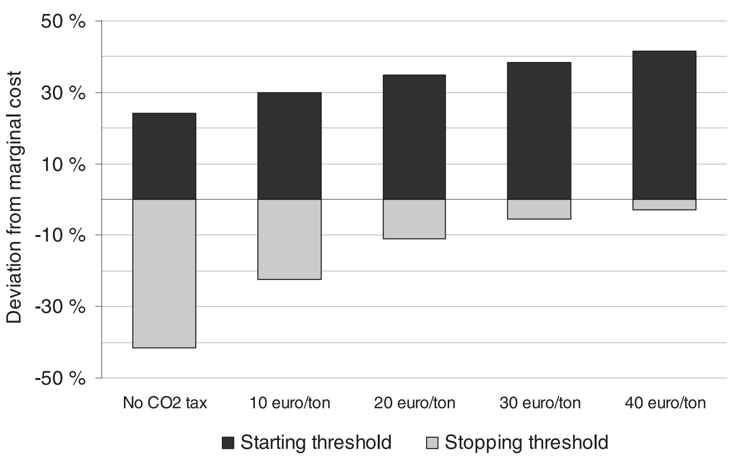
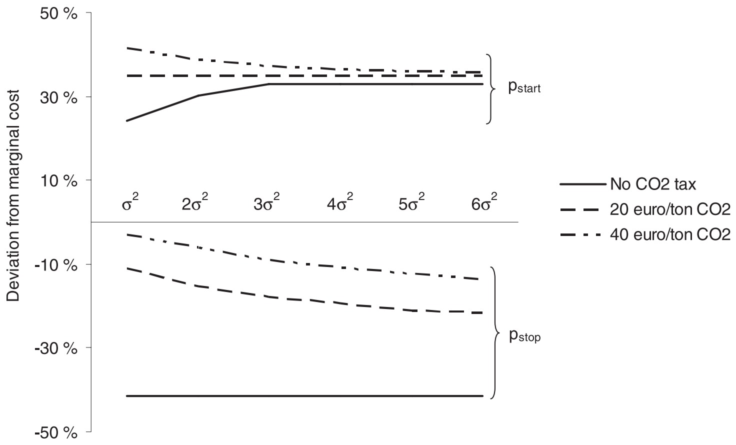


Figure 5. Starting and Stopping Thresholds (Relative to Marginal Costs) for Different CO_2 Cost and Power Price Uncertainty Levels – Sensitivity with Lower Expected Power Price



6.2 Is the Danish Example Relevant?

How do the figures compare with the observed price variation? In West Denmark, where wind power capacity increased 30% from 2000 to 2003, comprising 32% of total production capacity, the price variation increased by 71% in the same period.[12] This is in the range where increasing price variation influences the flexibility of a plant. A further increase in price variation will still have some effect on the threshold values and flexibility, but further changes will have diminishing effects.

It is also appropriate to question the extent to which the results are relevant for power markets in other countries. Denmark serves as a good example for the effects climate policy may have. For example, there has been a considerable increase in wind power capacity, including offshore wind parks, during the last few years, and further expansion is planned. Much of the remaining capacity consists of conventional thermal power plants, that is, plants where start and stop costs are important. Wind power produced about 5–7% of total electricity in 2005 in countries such as Spain, Germany, Ireland and Portugal, and further expansion is planned. Large wind parks are also planned in the United Kingdom and Sweden. The main difference to many other countries lies in the fact that Denmark is well connected to the Nordic power system, with a high share of flexible hydropower capacity (although bottlenecks do occur). Thus, unexpected wind power production can be easily accommodated in the system, without resulting in price spikes.

12. Other reasons, for instance the above-mentioned drought in Norway and Sweden, may have contributed to increased price variation as well.

Consequently, prices vary less between day and night in the Nordic system than, for instance, in Germany. A less flexible system that is more dominated by thermal production capacity (including nuclear and biomass-fired power plants) will probably experience higher price variation. Similarly, large wind parks in isolated areas will have more impact on prices in the region than dispersed windmills.

The cost estimates used in this example will certainly differ between countries, but the magnitude of variation is limited, as long as similar conventional technologies are used. The costs of a thermal power plant depend on the age of the plant and on fuel costs. Fuel prices will differ somewhat, depending on transport costs to different locations, but the difference is limited, since coal and fuel oil are traded in the world market.

7. CONCLUDING REMARKS

Start-up costs introduce inertia in the production decision. On the one hand, an idle producer will not start if the price is just slightly higher than the short-term marginal cost. On the other hand, if he is already producing, the producer will not stop immediately if the price falls below the marginal cost. Thus, total production may be either lower or higher than that predicted by short-run marginal costs alone.

This paper analyzes the impact of climate policies on a thermal power producer's production decision in the short term. The impact of greater price variation (as a result of the development of wind power) and higher costs (stemming from tradable emission permits for CO_2) on the threshold prices for optimal starting and stopping of the plant are analyzed.

Higher price variation makes the thermal power producer less flexible: the starting threshold increases and the stopping threshold falls. A larger price change is therefore necessary before it is optimal to change the operational status. The effect on total production and emissions is ambiguous: although some start-ups are avoided, some stops are also avoided.

A price on CO_2 increases both the marginal cost and the start-up cost of a power plant, as well as the expected power price. The numerical results show that for the marginal producer, the impact of the start-up cost on the producer's operation decision diminishes and the producer becomes more flexible. As both the starting and stopping thresholds are closer to the marginal cost, the operation decision resembles more the conventional 'price vs. marginal cost' rule. This implies lower emissions.[13]

However, if the CO_2 cost is coupled with higher power price variation due to more wind power,[14] the positive effects may be reversed as the two policies

13. Even though the emission level is known in an ideal cap-and-trade system, the costs of achieving the emission reduction are not. The EU ETS has made the uncertainty around the costs of domestic emission reduction visible, and policy-makers have been concerned about the burden placed on domestic industries when allocating the quotas for the Kyoto period of 2008–2012.

14. The CO_2 price may also lead to higher power price variation.

have opposing effects. Which effect dominates depends on the parameter values. Targeting the externality directly yields best results, while use of several policy measures at the same time may lead to undesired effects.

Introducing the CO_2 cost may have different impact on different power plants. A more expensive (i.e., not marginal) power plant may become *less flexible* when starting is considered, requiring higher power price before it is profitable to turn on the plant. This implies lower emissions, but also higher power prices and possibly higher power price variation.

The focus of this paper is how climate policies influence the production decisions of a *single* producer. This gives an indication of the impact of climate policies on production and emissions, but it is not possible to conclude the total effect on emissions by looking at a single producer; the interaction between several producers in a market determines the production pattern of each producer and hence total emissions. Moreover, as the start-up process involves higher fuel use than a continuous mode of production, the starting process itself causes CO_2 emissions. Hence, the total emissions of a power plant depend on the total number of starts and stops, in addition to total production, during a given period. The interaction of different producers in a market is further studied in Rosnes (2005) and Rosnes (2007).

An important implication of the present analysis is that the technicalities – both the technology mix in a power system and the policy design – are of significance to the climate policy outcomes. While the growing literature on wind power integration (see e.g., Gross et al. (2006) for a review) has focused mainly on the technical aspects (impacts and costs for system balancing and reliability and the improvement of wind power forecasts) and used statistical methods and simulation models for predictions, this paper points out that the conventional producers' production decision may be altered in different ways by the different combination of climate policies. Hence, the present analysis sheds light on an area in the intersection of economics and engineering that has been largely neglected so far. Recent developments in wind power and the trend towards large wind parks has concerned the system operators and sparked studies that combine the technology know-how of industry practitioners with policy analysis. One of the conclusions of Gross et al. (2006), a fine example of this kind of analysis, is that the impacts of wind power expansion must be considered in the context of a particular system – there is no ideal policy design that is suitable everywhere.

A policy design that fails to take into account the characteristics of the power system may lead to poor results: either greater emissions or a higher quota price than expected.

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Essay 2

Carbon Costs in Power Markets: The Importance of the Flexibility of Power Plants

Carbon Costs in Power Markets: The Importance of the Flexibility of Power Plants

Orvika Rosnes*†

Abstract

This paper analyzes how the effects of introducing a CO_2 cost in a power market depend upon the flexibility of the market. The start-up costs in thermal power plants constitute inflexibility that may hinder fuel switching, thus making it more costly to reduce emissions.

The results show that the effectiveness (in terms of the achieved reduction of emissions) of a given level of CO_2 cost depends on the flexibility of the power system. At some CO_2 cost levels, an inflexible system yields higher reductions in CO_2 emissions than a flexible system. In other words, inflexibility enhances the climate policy. For other levels, however, inflexibility counteracts the climate policy and a substantially higher CO_2 cost is required to achieve the same emission reduction. Hence, it is important to take the flexibility of the power system into account when assessing the effect of CO_2 pricing on emissions.

Keywords: Electricity, start-up costs, climate policy, CO_2 cost
JEL classification: C61, L94, Q48, Q58

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1 Introduction

The renewed focus on climate change issues has directed attention to short-term measures to reduce greenhouse gas emissions: the European Union's Emission Trading Scheme (EU ETS), for instance, imposes emission constraints that must be achieved within the limits of existing capacity (EC, 2003). A CO_2 cost – implemented either as a tax or through an emission trading system – changes the relative costs of different fuels and thereby alters the basis for interaction in the power market. However, the outcome of a CO_2 cost depends on the flexibility of the power system. A lack of flexibility, due to start-up costs and other technical constraints in power plants, may either facilitate or counteract the reduction in emissions in the short term.

Thermal power plants have significant costs related to the starting and stopping of the plant (Wood and Wollenberg, 1996). These start-up costs not only make the power plants more expensive, but also reduce their flexibility: Rosnes (2008) finds that the optimal threshold prices for starting and stopping deviate from marginal costs. Accordingly, the producer often prefers to produce nonstop and carry some short-term loss in order to avoid start-up costs later.

The production pattern of a single producer is determined in the interaction with other producers (and consumers) in a market. In a flexible, competitive market, power plants produce according to marginal costs: the cheapest (most efficient) plants are used first, while more expensive plants are employed when additional capacity is required.[1] When start-up costs are present, however, it is not necessarily the producers with the lowest marginal costs that produce at every instant. Due to the trade-off between continuous production and a shutdown (implying a start-up later), more expensive plants (in terms of marginal costs) may produce nonstop and

[1] This ordering of plants according to marginal costs is termed *merit order*.

replace cheaper plants.

Introducing a CO_2 cost[2] increases both the marginal production costs and the start-up costs of a power producer using fossil fuels. Because of the varying carbon content of fuels, *fuel switching* is expected to take place as a result of higher CO_2 costs: low-emission technologies (e.g., gas-fired power plants) replace high-emission technologies (e.g., coal-fired power plants). In the long term, this fuel switching mechanism works through investments: new and cleaner technologies replace older, more polluting technologies (as shown by Amundsen et al. (1999), Hauch (2003), Hindsberger et al. (2003) and Unger and Ahlgren (2005) in the context of the Nordic power market). In the short term, fuel switching must take place within the limits of existing capacity: existing producers replace each other in daily production.

However, the start-up costs may prevent short-term fuel switching from taking place as expected. Because of the start-up costs, a coal-fired power plant is not necessarily replaced by a gas-fired power plant, in spite of the higher CO_2 cost, thus making it more costly to reduce emissions. Inflexibility in the power system may counteract the climate policy. Accordingly, predictions about emissions based on 'smooth' production functions (as commonly assumed in economics) may be flawed, or, in a cap-and-trade system, the costs to achieve a desired emission reduction may differ from what is expected. Moreover, as the starting process causes additional emissions, total emissions from a power plant depend on the total number of starts and stops during a certain period, in addition to the total level of production.

The issues related to start-up costs and similar short-term constraints have been largely neglected in the economics literature.[3] The few exceptions confirm

[2] If there is no uncertainty, the optimal tax rate equals the price of tradable permits in equilibrium and the choice of policy instruments is irrelevant (Baumol and Oates, 1988). In the following, I refer to the climate policy instrument as 'CO_2 cost', reflecting the fact it can be achieved either through a tax or through permit trade.

[3] These issues have been thoroughly studied in the electrical engineering literature, see e.g., Sen and Kothari (1998) or Sheble and Fahd (1994). However, this literature has a different focus, being largely concerned with improving the solution algorithms for the operation of large power

their significance: Mansur (2003) finds in an empirical analysis of market power in the PJM (Pennsylvania, New Jersey, Maryland) power market that start-up costs may explain part of the price–cost margin in producers' bids previously ascribed to market power abuse. Tseng and Barz (2002) study asset valuation and find that failure to take into account start-up costs and other short-term constraints leads to overvaluation of a power plant. Rosnes (2008) shows how climate policies (CO_2 tax and increased production from renewables) alter the optimal starting and stopping thresholds of a fossil-fueled power producer. All of these studies suggest that the start-up costs substantially alter a *single* thermal power producer's production decision in the short term.

This paper fills the gap in literature by taking the analysis of Rosnes (2008) one step further: the start-up costs and other short-term constraints are included in a *market*, thereby making it possible to study the short-term interaction between different producers. The aim is to study the impact of flexibility in a realistic power market, therefore the numerical model is calibrated with current data from Western Denmark.[4] Denmark is part of the Nordic power exchange Nord Pool, where price is quoted for each hour. Therefore, hourly time resolution and discrete time framework are appropriate.

The theoretical model is set in an infinite horizon context and allows for simultaneous optimization over an unlimited number of periods. In practice, the distinct weekly pattern in power demand invites for simultaneous optimization over a week, followed by the next week, and so on infinitely. The numerical model therefore assumes simultaneous optimization over a week in the context of an infinite number of weeks.[5] Given that the weekly demand pattern is identical for all weeks, it can

systems. Climate policy issues have not received any attention.

[4] Western and Eastern Denmark constitute separate power systems with no (direct) connection between them.

[5] This is different from Nord Pool, where the market is cleared simultaneously for each of the 24 hours of the following day. Real-time market, that operates close to the actual hour of operation,

be shown that optimization over a week solves the full intertemporal optimization problem.

By including new features and having a considerably finer time resolution than what is common in power market models in economics, the implications of this short-term analysis can complement the results of longer term (e.g., annual) models (such as Amundsen et al. (1999), Hauch (2003), Halseth (1998) and Johnsen (1998) in the Nordic power market).[6] The focus of this paper is on how emissions for a given level of a CO_2 cost depend on the flexibility of a power system.

2 The model

Consider a partial equilibrium model for a power market, with a representative consumer and several thermal power producers.

The producers submit bids stating their willingness to produce at each price level to a market operator.[7] The market operator reviews the bids from all the producers and, by choosing the producers in increasing order of the bids, simultaneously determines production of all power plants in every period t (e.g., hour) throughout a planning horizon T (e.g., a day or a week). In other words, the market operator acts as a social planner, given the producers' bids. All producers are price takers.

Capacity is fixed and there is no uncertainty about fuel prices.

ensures that deviations between the planned and actual production and demand are balanced.

[6] Because of the computational complexity of integer modeling necessary for the proper representation of start-up costs, incorporating the short-term features in a sufficiently detailed manner in a simultaneous optimization of a longer period is not feasible.

[7] There is always a market operator in a power market because of the severe consequences of even a short-term market imbalance. This task is either performed implicitly by a system operator or explicitly by a power exchange (such as Nord Pool in the Nordic region).

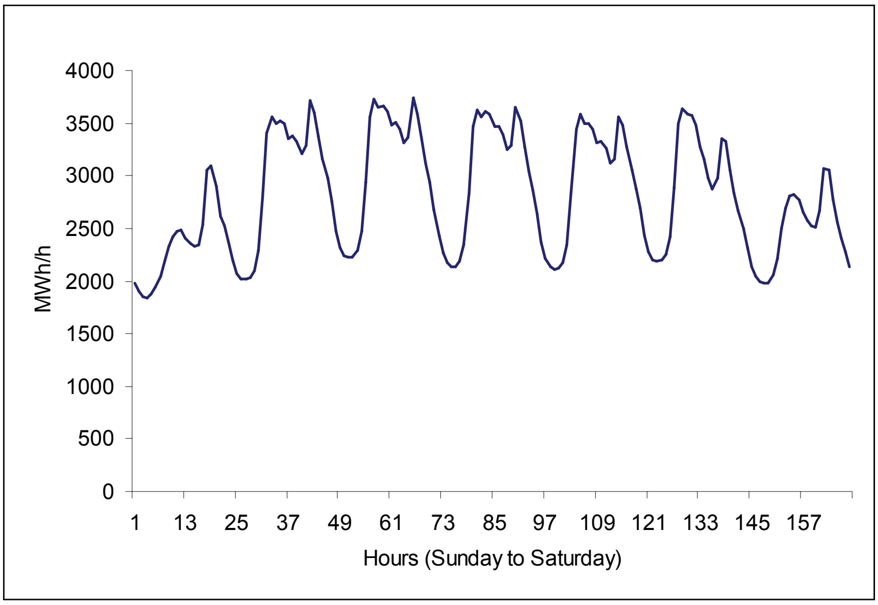

Figure 1: Demand in Western Denmark in a week in January 2006.
Source: www.energinet.dk

2.1 Demand

The representative consumer's demand for electricity in period (hour) t is q_t^D.

There is a pronounced daily *systematic* variation in power demand: demand is typically higher during the day than during the night. This systematic demand variation is taken into account in the model: q_t^D varies according to the pattern shown in figure 1.

Stochastic variation in demand (e.g., due to weather conditions) is not taken into account in this model because of computational limitations. The implications of this simplification are discussed in section 5.

Demand is assumed to be price inelastic. Inelastic demand is quite a realistic description of the situation in Denmark. Most consumers' demand is virtually inelastic in the very short term (from one hour to another): as consumers do not see hourly prices in real time, they do not respond to hourly prices. Besides, the possibility to reduce power demand in the short term is very limited: demand reduction typically requires investments (e.g., in new electrical equipment). Most importantly, however, the assumption of inelastic demand allows us to get to the heart of the matter – the impact of inflexibility in the power market. The importance of this assumption is commented on further in section 5.

2.2 Thermal power producer

Consider a firm i that can produce q_{it} units of output of homogenous product electricity in each time period t. The *operational marginal production costs*, denoted by c_i, involve the costs of producing an additional unit of output when the plant is already running. The operational marginal costs depend on fuel price ρ_i and on plant properties that determine fuel use in plant i, denoted by $\boldsymbol{\phi}_i$:

$$c_i = c(\rho_i, \boldsymbol{\phi}_i) \tag{1}$$

Due to the short time horizon, there is no uncertainty about fuel prices.

In addition to the operational marginal costs, the producer faces a *start-up cost* C_{it}^{start} if he did not produce in the previous period (hour) and starts to produce in this period (hour). The start-up costs consist of *direct* and *indirect* start-up costs.

The *direct* start-up cost C_{it}^{fuel} reflects the cost of extra fuel use during the start-up phase that is necessary in order to bring the boiler to the correct operating temperature before a single kilowatt-hour (kWh) can be produced. The necessary fuel use depends on the plant properties $\boldsymbol{\phi}_i$, but also on how many periods the unit has been shut off before being turned on again, measured by γ_{it}. If it has been off for a long time, so the boiler is cold, total *cold start cost* C_i^{Cold} is incurred. If the unit has been turned off only recently and the boiler temperature is still close to the operating temperature, the necessary fuel use is considerably lower.[8] Denote the

[8] This is called a *hot start* in the industry jargon.

fraction of cold start costs that occurs when the plant has been off for γ_{it} periods by $\varphi_t(\gamma_{it})$. The direct fuel costs of starting plant i in period t (when the plant has been off γ_{it} periods) are then:

$$C_{it}^{fuel} = C_i^{Cold}(\rho_i, \boldsymbol{\phi}_i) \cdot \varphi_t(\gamma_{it}) \tag{2}$$

The direct start-up costs are thus lower when the unit is turned on and off frequently than when it is kept offline for a long time before being turned on again, *ceteris paribus.*

The *indirect* start-up costs $C_i^{indirect}$ are related to the increased wear and tear from start-up that reduce the life-time of the plant. $C_i^{indirect}$ is a fixed cost per start.

Total start-up costs (the sum of direct and indirect costs) in period t are thus:

$$C_{it}^{start} = C_i^{Cold}(\rho_i, \boldsymbol{\phi}_i) \cdot \varphi_t(\gamma_{it}) + C_i^{indirect} \tag{3}$$

For each period t, the producer must decide whether to operate and, if he chooses to operate, the optimal production level. In other words, there are *two decision variables*: the binary variable x_{it} ($x_{it} = 1$ for *operate*, $x_{it} = 0$ for *not operate*) and the continuous variable $q_{it} \in \left[q_i^{\min}, q_i^{\max}\right]$ for the production level.

The decisions in each period depend on the *states* at the beginning of period t :

- a binary variable d_{it} indicating the status of the plant at the beginning of the period ($d_{it} = 1$ if *on*, $d_{it} = 0$ if *off*),
- a discrete variable γ_{it} indicating the number of hours the plant has been *off,* $\gamma_{it} \in [0, \infty)$,
- a continuous variable p_t for output price level, with a state space $p_t \in (-\infty, \infty)$.

The *equations of motion* for the three state variables are:

$$
\begin{aligned}
d_{it} &= h(x_{it-1}) = x_{it-1} && (4)\\
\gamma_{it} &= g(\gamma_{it-1}, x_{it-1}) = (\gamma_{it-1} + 1)(1 - x_{it-1}) && (5)\\
p_t &= p(q_t) && (6)
\end{aligned}
$$

Equation (4) shows that status at the beginning of period t depends on whether the plant operated or not in period $t-1$. Equation (5) counts how many periods the plant has been off. Equation (6) is the market (producer) price in equilibrium, determined in the implicit auction by the market operator (explained in section 2.3 below). Even though the producer does not observe the price at the beginning of each period t, the producer's bids are contingent on prices.

The profit π_{it} in period t depends on both the state variables p_t, γ_{it} and d_{it} at the beginning of the period, and on the actions x_{it} and q_{it} in period t :

$$\pi_{it}(p_t, d_{it}, \gamma_{it}; x_{it}, q_{it}) = [(p_t - c_i)q_{it}]\, x_{it} - C_{it}^{start}\,(1 - d_{it})\, x_{it} \tag{7}$$

and on equations (1) to (6) and the capacity constraint (8):

$$q_i^{\min} \leq q_{it} \leq q_i^{\max} \tag{8}$$

The start-up costs link the production and operating decisions in different periods together: that is, the profit in one period depends on the decisions made in other periods. Therefore, it is not necessarily the 'price vs. (operational) marginal cost'–rule that determines the production level in each period. Instead, the thermal power producer considers the flow of profits during the entire life-time of the power plant (which, if counted in hours, can be regarded as infinite). The optimal action is the one that balances the immediate payoff and the expected flow of future payoffs.

The value function $F(p_t, d_{it}, \gamma_{it})$ expresses the maximum achievable payoff throughout the entire planning horizon, given the present states:

$$F(p_t, d_{it}, \gamma_{it}) = \max_{\{x_t, q_t\}} \left\{ \pi_{it}(p_t, d_{it}, \gamma_{it}; x_{it}, q_{it}) + F(p_{t+1}, d_{t+1}, \gamma_{t+1}) \right\} \tag{9}$$

Equation (9) is the Bellman equation and expresses the trade-off between the immediate payoff, $\pi_{it}(p_t, d_{it}, \gamma_{it}; x_{it}, q_{it})$, and the future payoffs, $F(p_{t+1}, d_{t+1}, \gamma_{t+1})$, that an optimizing agent must balance.

The Bellman equation (9) determines the thermal producer's optimal bid schedule that he submits to the market operator. The bid schedule may specify a combination of price level and duration of a price level for which he is willing to produce (similar to the block bids at Nord Pool), and the bids may be negative, reflecting the willingness to carry a short-term loss in order to avoid a shutdown.

2.2.1 Emissions

Use of some input fuels v_{it} causes emissions. The emissions of producer i in period t, e_{it}, depend on the carbon content of the fuel used by producer i, denoted by the emission coefficient θ_i :

$$e_{it} = \theta_i v_{it} \tag{10}$$

Total emissions are the sum of the N firms' emissions in T periods:

$$E = \sum_t^T \sum_i^N e_{it}$$

2.3 Market equilibrium

The market must be in equilibrium in each period t, balancing production from the $i = 1, ..., N$ thermal power plants to meet demand:

$$\sum_{i=1}^{N} q_{it} = q_t^D \tag{11}$$

The market operator reviews bids from all producers and, by choosing the producers in increasing order of the bids, simultaneously determines production of all power plants in every period t (hour) throughout the whole simultaneous planning horizon T (week). Given that demand in each hour is fixed, the market operator minimizes total production costs (marginal and start-up costs) for the given level of demand. The solution to eq. (11) determines the equilibrium price p_t in each hour t.

2.4 Climate policies

Since there is a unique relationship between fuel use and emissions in each plant, a differentiated fuel tax is equivalent to an emission tax per unit of emissions.[9] The fuel tax rates τ_i depend on the carbon content of the fuel: $\tau_i(\theta_i)$. The tax changes both the marginal costs (eq. 1) and the fuel-related part of the start-up costs (eq. 2):

$$c_i = c(\rho_i + \tau_i(\theta_i), \boldsymbol{\phi}_i) \tag{12}$$

$$C_{it}^{fuel} = C_i^{Cold}(\rho_i + \tau_i(\theta_i), \boldsymbol{\phi}_i) \cdot \varphi_t(\gamma_{it}) \tag{13}$$

[9] Common (1977) has shown that as long as there is unique relationship between input and emissions, a tax on input is equivalent to a tax on emissions.

As a result of an increase in both the marginal cost and the start-up cost, the bids reflecting the willingness to produce at each price level will change. Moreover, because of the differentiated tax rate, the merit order will change: plants with lower emissions will become relatively cheaper to operate than plants with higher emissions. As a consequence, the equilibrium production pattern of the producers will change.

3 Data and assumptions in the numerical model

The numerical model[10] developed to analyze the effects of start-up costs in a market is populated with current data from Western Denmark. The model solves simultaneously for the optimal power production in each hour of a week ($t = 1, ..., 168$).

However, in order to reflect the infinite planning horizon of thermal power producers, it is assumed that this week is followed by an identical week *ad infinitum*; that is, the terminal condition assumes that demand after Sunday night is equal to demand on the preceding Monday.[11]

3.1 Demand and exogenous production

Demand is fixed and varies according to a predetermined profile. Data for one week in January 2006 is used for demand (figure 2).

Figure 2 also shows production in wind power and small combined heat and power (CHP) plants.[12] Production in these plants is included in the model exogenously, according to predetermined profiles, in order to arrive at the correct *net* demand that must be met by the (large) thermal power plants that are the focus here. Small CHP production is, in fact, determined by heat demand, which shows a

[10] The model is developed in the GAMS programming language (Brooke et al., 1998).
[11] In reality, the next week is fairly similar, but not identical due to seasonal variation.
[12] So-called *decentral* power plants.

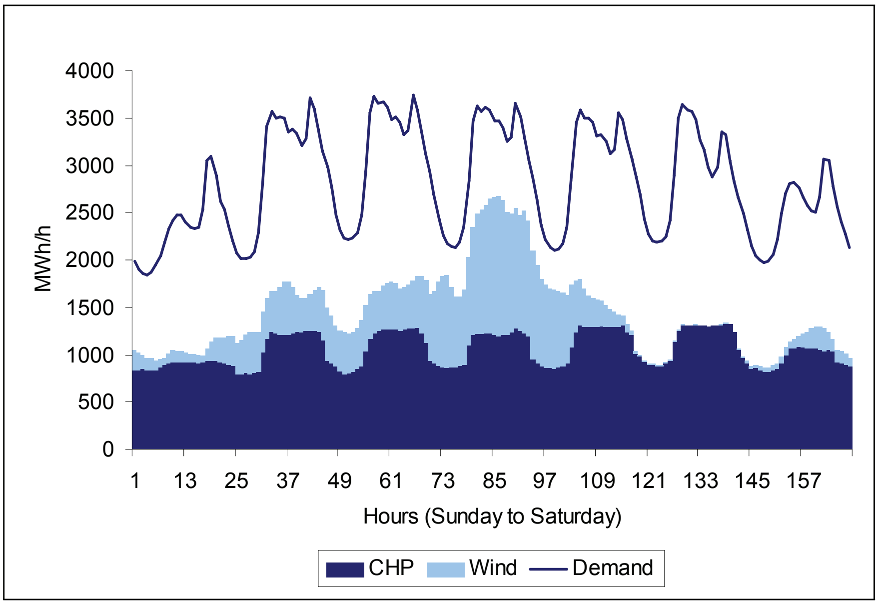

Figure 2: Demand and production in CHP and wind power plants (production levels are added) in Western Denmark in January 2006. Source: www.energinet.dk

consistent pattern over a week similar to power demand, and electricity is merely a by-product. Wind power production, however, varies and does not follow any clear pattern (as can be seen from figure 2): wind power can only be produced when there is wind. However, as a simplification, a fixed profile is used for wind power production.[13]

3.2 Thermal power plants

The focus here is on fossil-fueled power plants and how start-up costs influence the production schedule and emissions in these plants. Therefore, the fossil-fueled power plants are modeled in detail. This category includes ten power plants of different sizes and characteristics that were available in Western Denmark in 2006 (table 1). All plants but one use steam turbine technology; the final plant (No. 10) is a gas turbine.

[13] Rosnes (2007) relaxes the assumption of fixed wind power production.

Plant ID	Capacity (MW)	Fuel (production)	Fuel (Start-up)
1	410	Coal	Heavy fuel oil
2	400	Coal	Heavy fuel oil
3	380	Coal	Heavy fuel oil
4	625	Coal	Heavy fuel oil
5	350	Coal	Heavy fuel oil
6	350	Coal	Heavy fuel oil
7	300	Coal	Heavy fuel oil
8	400	Natural gas	Natural gas
9	240	Natural gas	Natural gas
10	50	Light fuel oil	Light fuel oil

Table 1: Power plants in the model, ordered according to rising marginal costs. Source: Company brochures

Production capacity is given and no investments occur in the short term. However, the production level in existing power plants can vary to meet the shifting demand.

The thermal power plants are characterized by a number of parameters in the model: age and technology, combined with fuel prices, determine the operational marginal costs and start-up costs of a plant. The different power plants included in the model are ordered according to the rising operational marginal costs in table 1. The corresponding fuel prices are listed in table 3 and are commented on in section 3.3 below. Capacity determines the upper limit of production ($q_i^{\max}$) in a power plant, while the minimum production requirement determines the minimum production level ($q_i^{\min}$) of a power plant, once it is operating; typically $q_i^{\min} = 0.3 \cdot q_i^{\max}$. Although a power plant can operate at different levels between the minimum production level $q_i^{\min}$ and maximum capacity $q_i^{\max}$, a loss in efficiency occurs at a less-than-optimal level, implying higher costs per kWh produced.

Table 2 illustrates the significance of the start-up costs, compared with the operational marginal costs, in some typical plants: a medium-aged coal-fired plant, a new natural gas-fired plant and a gas turbine. The coal-fired plant is cheaper in

	Coal	Natural gas	Gas turbine
Capacity (MW)	400	400	50
Efficiency (%)	45	49	32
Operational marginal cost (DKK/MWh)	147	206	892
Start-up: fuel cost of cold start (DKK/start)	55 600	30 000	4 400
Start-up: indirect cost (DKK/start)	453 400	294 000	18 800

Table 2: Marginal and start-up costs of selected power plants. The author's calculations

continuous operation than the natural gas-fired plant, while the start-up costs of the natural gas-fired plant are lower than those of the coal-fired plant. The fuel cost of one start-up in the coal-fired plant is equivalent to the cost of producing at the maximum production level for about one hour. When the indirect costs are also taken into account, the cost of one start-up in the coal-fired plant corresponds to about eight hours of production costs. For the gas-fired plant, the fuel cost of one start-up corresponds to the production cost in $\frac{1}{2}$ hour and the total start-up costs, including the indirect cost, to four hours of production costs. The gas turbine has much lower start-up costs than the other plants, but the marginal production cost is considerably higher. Therefore, the gas turbine is typically used for relieving shortage situations that last only a few hours; it is not intended for prolonged production.

The level of direct (fuel-related) start-up costs depends on how many periods (hours) the plant has been off before it is turned on again. However, while the start-up costs differ considerably when the unit has been off for one or two hours, the difference is much smaller when the unit has been off for about ten hours and is almost non-existent when the unit has been off more than twenty-four hours. Therefore, in order to reduce the complexity of the numerical model, the direct start-up costs (eq. 2) are approximated by a stepwise linear function as illustrated in figure 3. The solid line depicts the actual fuel costs (as a fraction of the full cold

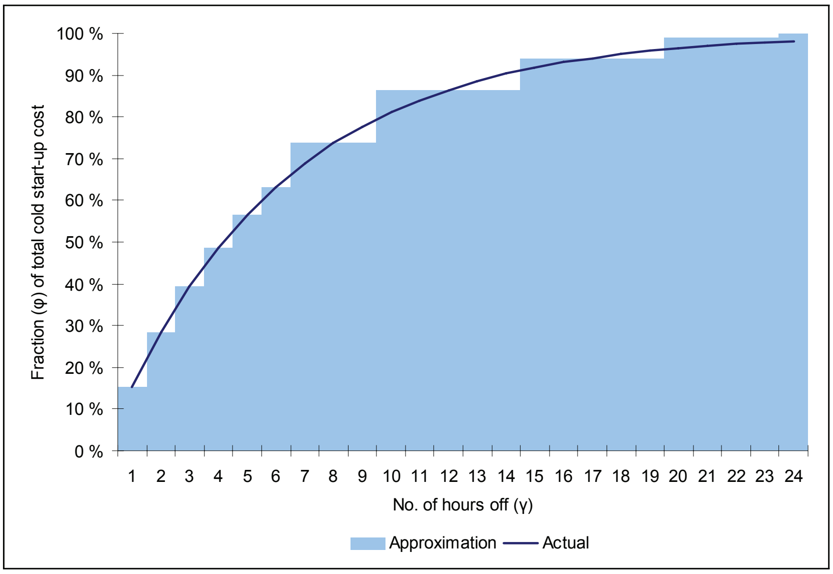

Figure 3: Time-dependency of direct start-up costs: actual and approximation used in the model

cost) of a start-up in every hour, depending on how many hours the unit has been off (measured by γ_{it}), while the stepwise linear function shows the approximation used in the numerical model.

Technically, all of the plants in the sample can start production within an hour. Therefore, other constraints that relate to a shorter period of time than an hour are not relevant in the model.

3.3 Fuel prices

Fuel (and CO_2) prices determine the operational marginal costs and the start-up costs of thermal power plants and, consequently, the relative competitiveness of the plants.

The assumptions relating to the fuel prices are shown in table 3. The fuel prices shown are averages of the 2005 level, except for the natural gas price. Compared with historical levels, the natural gas price was high throughout 2005. Therefore,

Coal	61	USD/ton
Heavy fuel oil	226	USD/ton
Light fuel oil	514	USD/ton
Natural gas (base case)	12.5	EUR/MWh
Natural gas (sensitivity)	17.4	EUR/MWh

Table 3: Fuel price assumptions

a lower natural gas price, reflecting historical levels, was used in the base case simulations. The importance of this assumption is tested in a sensitivity analysis using the 2005 average gas price (section 4.2.2).

There is no uncertainty about fuel prices. This is realistic in the short term: the day-to-day variation in fuel prices is usually negligible, and the price of the fuel stored at the plant is known with certainty.

3.4 CO_2 cost level

The model simulations have been carried out for various CO_2 cost levels in the range of 0 to 40 EUR/ton CO_2. There has been significant variation in CO_2 prices: before 2005, most analysts expected prices in the range of 5–8 EUR/ton CO_2. Since trading started in the EU ETS market in January 2005, prices for emission allowances in the 2005–2007 trading period have varied in the range of 0–30 EUR/ton. Much of this variation can be ascribed to the immaturity of the market and a lack of information. This is likely to be eliminated as more information becomes available. The penalty level of 40 EUR/ton CO_2 set the upper limit for prices. Expectations about allowance prices in the Kyoto period (2008–2012) followed the 2005–2007 spot prices to some extent. However, because the market is expected to be considerably tighter in the Kyoto period, the forward prices have stayed in the range of 15–25 EUR/ton.

4 Importance of flexibility

Variation in demand must be accommodated by the market: production in the different thermal power plants must vary accordingly in order to maintain the balance in the market. Seeing that we are looking at a closed system, without trading possibilities, and because demand is fixed, total production is the same in all cases. *Which particular plants* produce in order to meet the varying demand in each hour and how the plants are scheduled differs from case to case.

Let me start by looking at the impact of the power plant flexibility (section 4.1), before introducing climate policies (section 4.2).

4.1 Impact of start-up costs

In the *flexible* case (modeled as if there are no start-up costs), production in a power plant can be instantly adjusted according to the change in market prices. In the market, power plants produce according to their operational marginal costs. In the *inflexible* case, this is not the case: start-up costs are taken into consideration in scheduling the production in the market in addition to the operational marginal costs. As a result, some plants are not turned off at once when the price falls below the marginal cost and, similarly, others are not turned on at once when the price is higher than the marginal cost. This leads to lower total production in some plants, compared with the flexible case, while others produce more.

This intuition is confirmed with the model simulations. The most visible change occurs within the so-called mid-merit[14] plants: plant No. 5 replaces plant No. 2 in the inflexible case (ref. to plant ID-s in table 1). Plant No. 5 is more expensive in terms of marginal costs than plant No. 2, and is turned on and off in the

[14]Mid-merit plants are plants in the middle range of the merit order, i.e., neither the cheapest nor the most expensive.

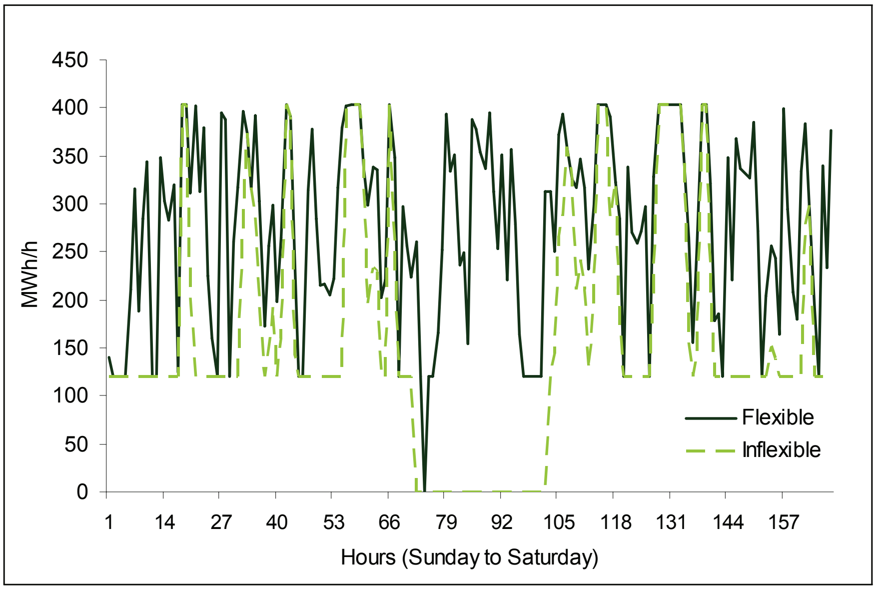

Figure 4: Production in power plant No. 2 without climate policies

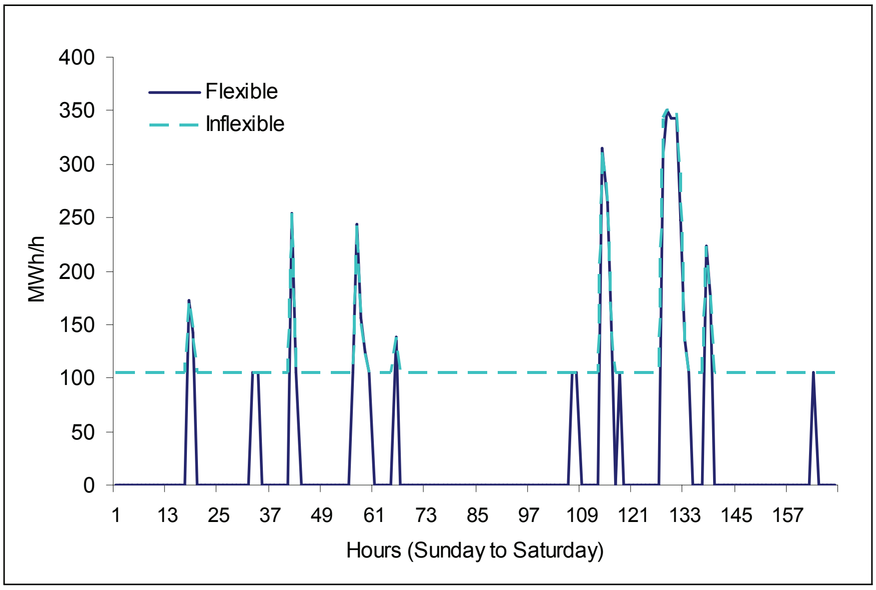

Figure 5: Production in power plant No. 5 without climate policies

flexible case to meet the peaks in demand. In the inflexible case, plant No. 5 produces continuously to avoid the start-up costs. In order to accommodate the higher production from plant No. 5, plant No. 2 must reduce production level. Figures 4 and 5 show production for these two plants in both scenarios.

Total costs are 6% higher in the inflexible case (table *4*, labeled *No climate policy*). The largest portion of the higher cost is due to the start-up costs (mainly indirect start-up costs). However, the pure production costs are also higher due to using plants with higher marginal costs (recall that plant No. 2 has lower operational marginal costs). Hence, increased production from plant No. 5 implies higher production costs.

Emissions

For power plants using the same fuel, there is a direct relationship between plant efficiency and the marginal costs and marginal emissions of a power plant. Thus, replacing an efficient plant with a less efficient plant translates directly into higher emissions. On the other hand, since the start-up process itself causes emissions, there is a trade-off between the emissions from start-up and the emissions from continuous production.

In the present example, the emissions are 1.4% higher in the inflexible case (table *4*). Most of this increase is due to higher production in plants with higher marginal costs. Emissions relating to start-up itself account for only 0.2% of total emissions.

4.2 Climate policy effects

What is the effect of introducing a CO_2 cost into this power system, and how does the effect depend on flexibility? In this closed system, climate policies work only through fuel switching, that is, changing the merit order. However, the start-up

	No climate policy		CO_2 cost 20 EUR/ton	
	Inflexible	Flexible	Inflexible	Flexible
Production (GWh)	230	230	230	230
CO_2 emissions (1000 ton)	175	173	160	169
Total costs (Mill. DKK)	35.9	33.8	61.7	59.5
– Production costs	34.2	33.8	36.1	34.4
– Start-up costs	1.7	0	1.8	0
– Emission costs	0	0	23.8	25.1

Table 4: Model results: impact of flexibility

costs may either enhance the fuel switching mechanism or counteract it.

Higher CO_2 cost implies both *higher marginal operational production costs* and *higher start-up costs* for plants that use fossil fuels (eq. 12 and 13). Since a different fuel is often used for start-up, the change in costs is not necessarily symmetric. Due to the different carbon content of fuels, the differentiated fuel tax changes the *relative* costs of producers: gas-fired power plants typically become cheaper relative to coal-fired power plants (but not necessarily in absolute terms).

In the flexible case, introducing a CO_2 cost of 20 EUR/ton reduces emissions 2% (table *4*). Production in a gas-fired power plant (No. 8) increases and replaces production in coal-fired power plants.

The remarkable result is that in the inflexible case, emissions are reduced considerably more – 9% from the no-tax case. Even in this case, the gas-fired plant (No. 8) replaces the coal-fired plants, but due to the start-up considerations, it replaces coal-fired plants *in even more hours*. In this case, inflexibility benefits the climate by enhancing fuel switching.

Note that emissions are 5% lower in the inflexible case than in the flexible case with the same CO_2 cost level.

	CO_2 cost level (EUR/ton):				
	0	**10**	**20**	**30**	**40**
Flexible case (no start-up costs)	172.7	172.8	168.6	150.0	147.1
Inflexible case (with start-up costs)	175.2	175.4	160.0	151.9	151.0
– from production	174.8	175.1	159.7	151.5	150.6
– from start	0.4	0.4	0.4	0.4	0.4

Table 5: Emissions with different tax levels (1000 ton)

4.2.1 Different CO_2 cost levels

Yet, the results above – that the emission reduction is larger in an inflexible system – is not general, but depends on the CO_2 cost level. For instance, with CO_2 cost levels of 30 and 40 EUR/ton, emissions are reduced *more* in the flexible case than in the inflexible case (table *5*). With these taxes, the gas-fired plants are used *more* in the flexible case, when they can be turned on and off when necessary; yet, they are still too expensive to be kept online all the time. Therefore, the start-up cost hinders fuel switching. Omitting inflexibility overestimates the emission reduction.

Moreover, virtually no further reduction of emissions is achieved by increasing the tax from 30 to 40 EUR/ton CO_2 in the inflexible case. The tax increase indeed changes the hourly merit order, but because of start-up costs, the less efficient coal-fired power plants also produce more. Inflexibility in production translates into inflexibility in emission reduction.

There is a similar situation for a tax increase from 0 to 10 EUR/ton. In this case, the carbon tax is not sufficiently high to rearrange the merit order, and no fuel switching to gas-fired plants occurs.

4.2.2 Higher gas prices

The results depend, of course, on fuel prices, most importantly the relative gas and coal prices. Fuel switching is considerably more costly with a higher gas price, and an even higher carbon cost level is required in order to change the merit order.

With a gas price of 17.4 EUR/MWh, there is virtually no reduction in emissions in the inflexible case with CO_2 cost levels in the range of 10–40 EUR/ton.

This illustrates the difficulty of reducing emissions in a power system heavily dependent on one or only a few technologies. If no other flexible technologies are available (as is the situation when gas prices are prohibitively high), the possibility of reducing emissions in a coal-dominated system by only shifting production between coal-fired power plants is very limited. This result may explain why so little fuel switching occurred in the EU ETS in the first half of 2005.

5 Concluding remarks

Start-up costs make conventional thermal power plants less flexible in the short term because it is costly to adjust production. A tax on CO_2 emissions increases both the marginal operational costs and the start-up costs of a power producer using fossil fuels, but also changes the relative costs of different producers and thereby alters the basis for market interaction. Since there is a trade-off between continuous production and shutdown that implies a start-up later, it is not necessarily producers with the lowest marginal costs and the lowest marginal emissions that produce at every instant.

The model results clearly show that the outcome of a CO_2 cost depends on the flexibility of the system: the start-up costs may, depending on the CO_2 cost level, either hinder or reinforce fuel switching. The emission reduction that is achieved by a certain CO_2 cost level varies, depending on the technology mix of the system. Alternatively, the CO_2 cost level that is needed in order to achieve a certain emission reduction depends on the flexibility of a system. In some cases, the cost may be higher than predicted by traditional market models. With unfavorable fuel price combinations, the costs associated with a certain emission reduction in an inflexible system may be excessive. Hence, when assessing the effect of CO_2 pricing on emissions from a power system or the costs associated with a specific emission reduction target, it is highly relevant to take flexibility into account.

The results of every numerical analysis depend on the assumed parameter values. The coal, gas and oil prices are the most critical parameter values in the present analysis, but parameters relating to technologies also play a role. Adjusting parameter values relating to start-up gives an indication of the impact that other technologies may have. The flexible case above may serve as an illustration for a hydropower system: hydropower can adjust quickly, so a system with enough hydropower alleviates the inflexibility in thermal plants. If hydropower capacity is large enough compared with the rest of the system, all adjustment is taken care of by hydropower and the thermal plants can produce nonstop. Nuclear power, on the other hand, is inflexible. In the present model, this would mean very high start-up costs and the plant would produce non-stop.[15] The ability to adjust production in the other plants is still equally relevant, if not more so.

The analysis emphasizes the importance of flexibility. Even though the analysis builds on a realistic representation of a power market, some important sources of flexibility are ruled out: namely, trade and demand.

Trade with a power system with different production technology may provide flexibility in the short term. Integrating a thermal system with a hydropower system enables the thermal power plants to produce nonstop, leaving the balancing task to hydropower. Hydropower alleviates the inflexibility of the system, thus making fuel switching easier. On the other hand, nuclear power plants are even less flexible than coal-fired power plants. Yet, neighboring countries often have similar technology and demand profiles. For instance, coal is by far the most common fuel in electricity

[15] This depends on nuclear capacity relative to demand, though nuclear plant size is normally adjusted to the size of the potential market.

production not only in Denmark, but in many European countries. Bottlenecks also occur on the existing transmission lines (for instance, there were bottlenecks between Western Denmark and Norway about 55% of the time in 2006). In these periods, a country or a region becomes an isolated system, as modeled here.

Another potential source of flexibility is demand. All the same, inelastic demand is not a gross exaggeration of reality – power demand is more or less fixed in the short term. Accordingly, promoting flexibility on the demand side may be a profitable way of reducing production costs and emissions in an inflexible system. Even a few flexible consumers may have a huge impact, especially in situations of scarcity.

Uncertainty is not accounted for in the numerical model due to computational limitations. Rosnes (2008) finds that higher uncertainty (for instance, from wind power or demand) leads to more inflexibility in a single plant: even higher prices are needed in order to turn on a plant than with full certainty, and even lower prices are necessary before the plant is turned off. This would probably magnify the results of the present analysis.

The analysis illustrates policy effects in a closed system, and as such is not an unrealistic representation. Even though Denmark as an isolated system is a simplification, the European electricity market forms a more or less closed system. The same climate policy applies to all countries and carbon leakages are restricted by the existing (limited) transmission lines. In this system, emissions can only be reduced by fuel switching in the short term. The analysis also demonstrates the complications of reducing emissions in the short term: the existing non-emitting (hydropower and nuclear power) capacity is fully utilized and the climate policy outcomes hinge on the mid-merit technologies, that is, coal- and gas-fired power plants.

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Essay 3

Subsidies to Renewable Energy in Inflexible Power Markets

Subsidies to Renewable Energy in Inflexible Power Markets

Orvika Rosnes*†

Abstract

This paper analyzes how the short-term operational efficiency and the emissions of a power system depend on different support schemes provided to wind power and on the flexibility of the power system. This is analyzed in the framework of a numerical power market model, calibrated to current Danish data where the start-up costs and other constraints in fossil-fueled power plants are taken into account.

The main conclusion is that flexibility is crucial for the costs of wind power integration. If thermal power plants are inflexible, subsidies to wind power should strive to increase the flexibility of the market by passing market signals through to wind power. A subsidy that conceals market signals from wind power producers (a production subsidy) or decouples wind power incentives from the market signals altogether (a fixed price) increases costs considerably. The implication is that an inflexible power system should aim to introduce optimal subsidies (a lump-sum investment subsidy) instead of production subsidies or a fixed price. Investment and production subsidies are not equivalent in the short term.

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1 Introduction

The European Union (EU) has an ambitious target of increasing the share of renewable energy in electricity production to 21% by 2010 (EC, 2001). The choice of a support scheme to promote renewable energy is, however, left to the individual Member States.[1] By considering the support to renewables as a measure to reduce the CO_2 emissions from electricity production, this paper analyzes the effectiveness and efficiency of different support schemes when technical characteristics (such as flexibility) of the existing electricity system are taken into account.

Even though the principal goal of the support is to promote investments in renewables, some subsidy schemes also influence the short-term production decisions of renewables once the investment is carried out. Investment subsidies influence only the choice of technology, leaving production decisions dependent on market prices; thus, investment subsidies may be considered as lump-sum subsidies regarding the short-term (daily) production decisions. Production subsidies, on the other hand, also influence the short-term production decisions: the renewable producer may often produce in order to collect the production subsidy, even if the market price is below the producer's marginal costs. A fixed producer price decouples the production incentive completely from the market signals.

Wind power – the preferred renewable energy source in many countries – may be challenging to accommodate in existing power systems due to its unique characteristics. Wind power represents a variable energy source: put simply, it is only

[1] The common support schemes in the EU – feed-in tariffs and tradable green certificates – are versions of a production subsidy. Feed-in tariffs (guaranteed prices for renewable electricity or guaranteed mark-ups on market price of electricity) are used in Denmark, France, Germany and Spain, among others (COM, 2005). In a green certificate system, electricity producers receive a certificate for every kWh of electricity produced from renewable sources. The certificate provides an extra revenue, in addition to electricity price, to renewable electricity producers. Tradable green certificates are used in Belgium, Italy, Sweden and the UK. Investment subsidies are in force in Finland and Portugal.

possible to produce wind power when the wind is blowing.[2] Thus, the available wind power production in a given hour may vary substantially during the day and is often significantly lower than the nominal installed capacity. On the other hand, due to low marginal production costs and the possibility of adjusting production easily and without cost within the limits of the available wind, one would expect wind power to be produced up to those limits at all times. This is further encouraged by a production subsidy.

The variation in wind power production must be immediately accommodated by other producers in order to maintain the system balance; thus, other power plants must vary their production accordingly. How easy it is to accommodate the variable electricity production from renewables in the market depends on the flexibility of the rest of the power system.

The flexibility of a power system depends first and foremost on power production technology.[3] Most countries in Continental Europe have power systems dominated by thermal power plants. Conventional coal-fired and natural gas-fired thermal power plants are relatively inflexible in the short term due to the costs related to starting the plant (Wood and Wollenberg, 1996). Hence, it is not only the operational marginal costs of every kilowatt-hour (kWh) in a continuous production mode (as commonly assumed in the economic literature), but also the costs of every start-up (or avoided start-up) that determine the thermal producer's production decision in any given hour. Given this, the power plant will occasionally produce, even when the price falls below the operational marginal cost, in order to avoid a shutdown; similarly, it might choose not to start production, even when

[2] Similarly, solar and wave power are also variable, while other renewable technologies (e.g., biomass-based combined heat and power) are more similar to conventional power plants or are flexible (e.g., hydropower).

[3] Hydropower, for instance, is more flexible than thermal power. The size and technology mix of the power system, the possibility for trade and flexibility of demand also play a role for flexibility of the power system. These issues are briefly discussed in sections 5 and 6 below.

the price exceeds the operational marginal cost (Rosnes, 2008). In a market with heterogenous producers, flexibility is as important a determinant of the individual power plant's production pattern as are operational marginal costs.

If an increase in wind power production in a given hour induces a thermal power plant to shut down, it is very likely that the thermal plant must start again later. Bringing the thermal unit back to operating temperature requires additional fuel, before a single kilowatt-hour can be produced. This extra fuel causes additional emissions. In this case, the emissions avoided by stopping the thermal power plant may be more than offset by higher emissions when the plant starts again. Moreover, due to the start-up costs, it is not necessarily the thermal power plants with the lowest emissions that will start next. Therefore, from the standpoint of minimizing costs or emissions from the power system as a whole, it may sometimes be optimal to reduce wind power production from its maximum available level, even though the wind power has lower marginal costs and no emissions, in order to avoid the shutdown of a thermal plant. Introducing wind power into a system dominated by thermal power plants increases the demand for flexibility from the remainder of the power system.

This implies that the design of the subsidy scheme should strive to maintain correct incentives to wind power in the short term: passing market signals to them would contribute to keeping additional costs and emissions at a minimum. An ill-designed subsidy scheme for renewables (i.e., one that conceals market signals and reduces the responsiveness to market prices), combined with an inflexible system, may amplify the adverse effects of renewables and contribute to excessive cost of emission reductions.

As the principal aim of supporting renewables is to reduce CO_2 emissions through crowding out fossil fuels,[4] it is relevant to examine whether a subsidy scheme con-

[4] Other goals, such as support to domestic industry or regional development, are maybe less

tributes to emission reduction and its cost. Rosnes (2005) shows that the outcome of a CO_2 tax in a power market crucially depends on the flexibility of power plants. The focus of studies analyzing different support schemes for renewables (e.g., Menanteau et al., 2003) has mainly been the *investment efficiency* of support policies, that is, to what extent do the policy measures stimulate investments in the most cost-efficient technologies.[5] Issues pertaining to short-term *operational efficiency* of renewables – the day-to-day or even hourly production efficiency – and the short-term interaction between wind power and thermal power have been neglected in the literature. Furthermore, the implications of the start-up costs of power plants have received very little attention in the economics literature so far, even though these issues have been extensively studied in the electrical engineering literature.[6] The few existing papers in economics confirm that the start-up costs do have implications for economic agents' behavior: in addition to Rosnes (2008) and Rosnes (2005) referred to above, Mansur (2003) shows in an econometric study based on Pennsylvania, New Jersey and Maryland data that power producers' bids in excess of marginal costs may be explained by start-up costs and do not necessarily reflect the abuse of market power, and Tseng and Barz (2002) find that failure to take into account the short-term constraints may lead to overvaluation of power plants.

This paper fills a gap in the literature by focusing on the effects of different support schemes for renewables on operational efficiency (short-term production costs)

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pronounced, but nevertheless evident in the variety of renewable support schemes in the EU countries.

[5] The interaction between a tradable green certificates market and the power market has been analyzed in a number of recent papers, including Amundsen and Mortensen (2001), Unger and Ahlgren (2005), Morthorst (2001), Jensen and Skytte (2003). However, these studies also focus on the medium to long term impacts of renewables.

[6] This strand of literature has, however, a different focus, being largely concerned with finding the solution algorithms for the actual operation of large power systems; see e.g., Sen and Kothari (1998) or Sheble and Fahd (1994). Environmental or climate policy issues have not been at the center of attention.

and effectiveness (in terms of emission reduction) in an inflexible power system. The aim of the analysis is to quantify the policy effects in a realistic power system. Therefore, this paper explores the implications of increasing wind power capacity in the Danish market.[7] Given its predominantly fossil-fueled thermal capacity, but with an ambitious goal of boosting wind power to meet 50% of electricity demand by 2025 from 20% at present (TRM, 2007), Denmark provides a highly relevant case for the analysis of flexibility. It is reasonable to assume that as long as wind power constitutes a small share of total production capacity, it is relatively easy to accommodate within the market, despite the possible distortion from subsidies. The adverse effects will become more pertinent as the share of wind power in electricity production increases or is concentrated in some geographical areas. Even though the policy document (TRM, 2007) emphasizes efficiency, it is again only investment efficiency that is the main point of focus. Taking the existing support policies as a starting point, this paper examines how a power system's overall operating costs and emissions are affected by three different subsidy schemes: a production subsidy (a mark-up on the market price per kWh produced), a fixed price per kWh produced (unrelated to market price) and an investment subsidy per MW invested (a lump-sum subsidy concerning the production decision).

2 The model

Consider a deterministic partial equilibrium model for a power market, with a representative consumer and two kinds of producers: a renewable (wind) power

[7] Amundsen et al. (1999), Halseth (1998), Hauch (2003) and Johnsen (1998) use similar partial equilibrium models for policy analyzes of the Nordic power market. However, the time horizon of these models is considerably longer (typically one year with only a few seasons and load periods), making them unsuitable for addressing the short-term issues relating to the start-up of thermal power plants. Hence, with a finer time resolution, the present model may complement the traditional long-term policy analysis.

producer and conventional thermal power producers. The wind power producer, being able to adjust the level of production easily and without cost, is perfectly flexible within the limits of the available wind, while the thermal power producers have limited flexibility due to the presence of start-up costs (the heterogeneity of thermal power producers implies different levels of flexibility; this will be detailed in section 3.2). All producers are price takers. There is no trade.[8] The model is set in an infinite horizon context and allows for simultaneous optimization over an unlimited number of periods.

The producers submit bids stating their willingness to produce at each price level to a market operator.[9] The market operator reviews the bids from all the producers and, by choosing the producers in increasing order of the bids, simultaneously determines production of all power plants in every period t (e.g., hour) throughout a planning horizon T (e.g., a day or a week).[10] In other words, the market operator acts as a social planner, given the producers' bids. Price for each period is determined in an implicit auction. Since this is a simultaneous one-time decision for each T, there is no learning throughout the planning horizon.

The focus is on the short-term interaction of wind power and thermal power, thus, capacity is fixed. Similarly, due to the short time horizon, there is no uncertainty about fuel prices.

The model is deterministic: there is no uncertainty about wind power production or demand in the model. However, the *variability* of wind power is taken into

[8]Even though Denmark has transmission lines to Norway, Sweden and Germany, trade possibilities are ruled out in the present analysis in order to focus on the inflexibility of thermal power plants. Whether this is a realistic assumption, and the implications, are discussed in section 6.1.

[9]There is always a market operator in a power market because of the severe consequences of even a short-term market imbalance. This task is either performed implicitly by a system operator or explicitly by a power exchange (such as Nord Pool in the Nordic region).

[10]This is similar to the Nordic power exchange Nord Pool, where the day-ahead market is cleared simultaneously for each of the 24 hours of the following day (see www.nordpool.com). Real-time market, that operates close to the hour of operation, ensures that deviations between the planned and actual production and demand are balanced. Therefore, a discrete time framework is appropriate.

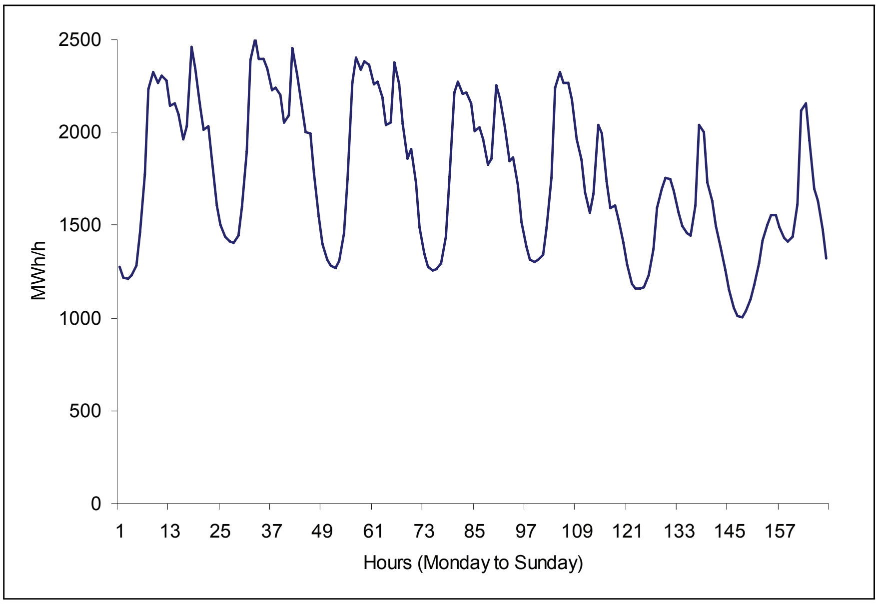

Figure 1: Electricity demand in Western Denmark throughout a week in January 2006. Source: www.energinet.dk

account, as well as the systematic variation in demand.

2.1 Demand

The representative consumer's demand for electricity in period t is q_t^D.

There is a pronounced daily *systematic* variation in power demand: demand is typically higher during the day than the night and on weekdays than on weekends. This systematic demand variation is taken into account in the model: q_t^D varies from hour to hour according to the pattern shown on figure 1.[11] This variation in demand must be accommodated by producers, requiring them to vary their production accordingly.

Demand is assumed to be perfectly price-inelastic in order to get to the heart of

[11] The figure shows the *net demand* faced by thermal producers and wind power combined, after subtracting the power supply of a third type of producer, namely small combined heat and power (CHP) plants. These plants primarily produce heat; power is merely a by-product. Thus, the power output from small CHPs is fixed.

the matter – the impact of flexibility in generation. The realism and consequences of this assumption are discussed further in section 6.2.

2.2 Thermal power producer[12]

Consider a firm i that can produce q_{it} units of output of the homogenous product electricity in each time period t. The *operational marginal costs*, denoted by c_i, involve the costs of producing an additional unit of output when the plant is already running. The operational marginal costs depend on input (fuel) price ρ_i and plant properties that determine fuel use in plant i, denoted by the vector $\boldsymbol{\phi}_i$:

$$c_i = c(\rho_i, \boldsymbol{\phi}_i) \tag{1}$$

In addition to the operational marginal costs, the producer faces a *start-up cost* C_{it}^{start} if he did not produce in the previous period (hour) and starts to produce in this period (hour). The level of start-up costs depends on how many periods the plant has been off before being turned on again. The start-up costs consist of *direct* and *indirect* start-up costs, and are sunk costs.

The *direct* start-up costs C_{it}^{fuel} reflect the cost of extra fuel used during the start-up phase to bring the boiler to the correct operating temperature before a single kilowatt-hour can be produced. The necessary fuel use depends on the fuel price ρ_i and plant properties $\boldsymbol{\phi}_i$, but also on how many periods the unit has been shut off, measured by γ_{it}. If it has been off for a long time, so the boiler is cold, total *cold start cost* C_i^{Cold} is incurred. If the unit has been turned off only recently and the temperature of the boiler is still close to the operating temperature, the necessary fuel use is considerably lower.[13] Denote the fraction of cold start costs

[12] The representation of the thermal power producer builds on the model developed in Rosnes (2005), included as Essay 2 in this thesis.

[13] This is called a *hot start* in the industry jargon.

that are incurred when the plant has been off γ_{it} periods by $\varphi_t(\gamma_{it})$. The direct fuel costs of starting plant i in period t (when the plant has been off γ_{it} periods) are then

$$C_{it}^{fuel} = C_i^{Cold}(\rho_i, \boldsymbol{\phi}_i) \cdot \varphi_t(\gamma_{it}) \tag{2}$$

The direct start-up costs are thus lower when the unit is turned on and off frequently than when it is kept offline for many periods before being turned on again, *ceteris paribus.*

The *indirect* start-up costs $C_i^{indirect}$ are related to the increased wear and tear from start-up that reduce the lifetime of the plant. $C_i^{indirect}$ is a fixed cost per start-up.

The total start-up costs (the sum of the direct and indirect costs) in period t are thus:

$$C_{it}^{start} = C_i^{Cold}(\rho_i, \boldsymbol{\phi}_i) \cdot \varphi_t(\gamma_{it}) + C_i^{indirect} \tag{3}$$

The producer must decide for each period whether to operate and, if he chooses to operate, the optimal production level. In other words, there are *two decision variables*: the binary variable x_{it} ($x_{it} = 1$ for *operate*, $x_{it} = 0$ for *not operate*) and the continuous variable $q_{it} \in \left[q_i^{\min}, q_i^{\max}\right]$ for the production level.

The decisions in each period depend on the *states* at the beginning of the period:

- a binary variable d_{it} indicating the status of the plant at the beginning of the period ($d_{it} = 1$ if *on*, $d_{it} = 0$ if *off*)
- a discrete variable γ_{it} indicating the number of periods the plant has been *off*, $\gamma_{it} \in [0, \infty)$
- a continuous variable p_t for output price level, with a state space $p_t \in (-\infty, \infty)$

The *equations of motion* for the three state variables are:

$$
\begin{aligned}
d_{it} &= h(x_{it-1}) = x_{it-1} && (4)\\
\gamma_{it} &= g(\gamma_{it-1}, x_{it-1}) = (\gamma_{it-1}+1)(1-x_{it-1}) && (5)\\
p_t &= p(q_t) && (6)
\end{aligned}
$$

Equation (4) states that the status at the beginning of period t depends on whether the plant operated or not in period $t-1$. Equation (5) counts how many periods the plant has been off. Equation (6) is the producer price, as determined by the market equilibrium. (Even though the producer does not observe the price at the beginning of each period t, the producer's bids are contingent on prices.)

The profit π_{it} in period t depends on both the state variables p_t, γ_{it} and d_{it} at the beginning of the period and the actions x_{it} and q_{it} in period t :

$$\pi_{it}(p_t, d_{it}, \gamma_{it}; x_{it}, q_{it}) = [(p_t - c_i)q_{it}]\, x_{it} - C_{it}^{start}\,(1-d_{it})\, x_{it} \tag{7}$$

given equations (1) to (6) and capacity constraint (8):

$$q_i^{\min} \leq q_{it} \leq q_i^{\max} \tag{8}$$

The start-up costs link the production and operation decisions in different periods together: profit in one period depends on the decisions made in other periods. Therefore, it is not necessarily the usual 'price vs. (operational) marginal cost'–rule that determines the production level in each period. Instead, the thermal power producer considers the flow of profits during the entire lifetime of the power plant. The optimal action is the one that balances the immediate payoff and the flow of future payoffs.

The value function $F(p_t, d_{it}, \gamma_{it})$ expresses the maximum achievable payoff throughout the whole planning horizon, given the present states:

$$F(p_t, d_{it}, \gamma_{it}) = \max_{\{x_{it}, q_{it}\}} \left\{ \pi_{it}(p_t, d_{it}, \gamma_{it}; x_{it}, q_{it}) + F(p_{t+1}, d_{it+1}, \gamma_{it+1}) \right\} \tag{9}$$

Equation (9) is the Bellman equation and expresses the trade-off between the immediate payoff, $\pi_{it}(p_t, d_{it}, \gamma_{it}; x_{it}, q_{it})$, and the future payoffs, $F(p_{t+1}, d_{it+1}, \gamma_{it+1})$, that an optimizing agent must balance.

Bids

The Bellman equation (9) determines the thermal producer's optimal bid schedule that he submits to the market operator. The thermal producer's bid schedule may specify a combination of price level and duration of a price level for which he is willing to produce,[14] and the bids may be negative, reflecting the shadow price of a start-up that is incurred if the producer has to stop.

Emissions

Use of some input fuels v_{it} causes emissions e_{it}:

$$e_{it} = \theta_i v_{it} \tag{10}$$

where θ_i is emission coefficient.

The total emissions are the sum of the N thermal producers' emissions during

[14] This bid schedule is similar to the *block bids* that are used at Nord Pool day-ahead market in addition to the common hourly bids. A block bid sets an "all-or-nothing" condition for all hours within the block, and must be accepted in its entirety. It is also possible to define links between block bids, making acceptance of one bid dependent on acceptance of another.

the whole planning horizon T:

$$E = \sum_{t}^{T} \sum_{i}^{N} e_{it}$$

2.3 Wind power producer

A wind power producer is more flexible than a thermal power producer: the wind power producer, having no start-up costs, can change production level easily and without cost within the limits of the available capacity. However, the available capacity varies, even in the short term, depending on the wind availability in each hour.[15,16] Thus, the wind power production $q_{wind,t}$ in each hour is limited both by installed capacity $q_{wind}^{\max}$ and by the availability of wind $\sigma_t \in [0, 1]$:

$$q_{wind,t} \leq \sigma_t q_{wind}^{\max} \tag{11}$$

Since there is no link between the costs in different periods, the wind power producer's decision is the usual static problem of choosing a production level to maximize the profit in each t, up to the available capacity limit:

$$\max_{\{q_{wind,t}\}} \Pi_t = (p_t - c_w) q_{wind,t} \tag{12}$$

[15]Availability depends on the wind force in every hour. In order to produce, there must be wind blowing. On the other hand, if the wind blows too hard, the turbines must be turned off in order to avoid damage. However, the exact relationship between wind force (as measured on the Beaufort scale or in m/s) and kilowatt-hours produced is not essential in this analysis. Therefore, the availability parameter σ_t represents the *available capacity converted into kilowatt-hours*. Any wind force that exceeds the possible production threshold is simply denoted $\sigma_t = 0$. Similarly, a windless moment implies $\sigma_t = 0$.

[16]There is also uncertainty about the availability of wind. This is, however, omitted in the present model owing to the computational infeasibility. Instead, it is assumed that wind power availability is known in each hour, but the availability varies. Recent developments in meteorological models have greatly improved the prediction of wind power availability, especially in the short term.

subject to eq. (11). The Kuhn–Tucker first-order conditions determine the optimal bids of the wind power producer:

$$p_t - c_w - \lambda = 0 \tag{13}$$

$$\lambda \left(q_{wind,t} - \sigma_t q_{wind}^{\max} \right) = 0 \tag{14}$$

Either eq. (13) or (14) is binding: when price exceeds marginal costs c_w, the wind power producer produces at the maximum level. λ is interpreted as the shadow price of capacity.

2.4 Market equilibrium

The market must be in equilibrium in each period t, balancing production from the $i = 1, ..., N$ thermal power plants and wind power to meet demand:

$$\sum_{i=1}^{N} q_{it} + q_{wind,t} = q_t^D \tag{15}$$

The market operator responsible for balancing the market reviews the bid schedules from all producers. By choosing the producers in increasing order of the bids and simultaneously optimizing over the next T periods, the market operator determines which producers will produce in each period. The solution to the market equilibrium determines the equilibrium producer price p_t in each period.

Both variation in demand and variation in wind power availability must be accommodated by the market – production in the different thermal power plants must vary accordingly in order to maintain the market balance. In the absence of start-up costs, producers with the lowest operational marginal costs produce first at all times. In the presence of start-up costs, however, it is sometimes cheaper to keep a power plant with higher operational marginal costs running than to use a power plant with lower operational marginal costs if this inflicts additional start-up costs. As the thermal power producers' bids may be negative, reflecting their willingness to carry a short-term loss in order to avoid shutdown, the producer price may be negative. In other words, producers may be required to pay in order to produce.

The wind power producer, on the other hand, has no reason to carry on producing with negative prices. The wind power producer is perfectly flexible within the limits of the available capacity: he can stop and start costlessly when the price exceeds marginal cost. Therefore, when confronted with negative prices, the wind power producer will reduce production from the maximum available level.

2.5 Subsidies to wind power

Subsidies to support wind power may influence the short-term production decision of the wind power producer and, hence, alter his bids. The altered bids affect the equilibrium solution – which producers will produce in different periods. Therefore, thermal power producers are also affected via the market, even though their bids are not affected by the subsidy to wind power.

2.5.1 Lump-sum investment subsidy

An investment subsidy is given as a lump sum S per unit of installed capacity. The short-term production decision of the wind power producer in this case becomes:

$$\max_{\{q_{wind,t}\}} \quad \Pi_t = (p_t - c)q_{wind,t} + Sq_{wind}^{\max} \quad \text{subject to} \quad q_{wind,t} \leq \sigma_t q_{wind}^{\max} \tag{16}$$

Since capacity is given in the short term, the first-order conditions are the same as without a subsidy (eq. 13 and 14). The lump-sum investment subsidy does not distort the short-term production decision, it only improves the profitability of the investment. Hence, it is an optimal subsidy regarding the short-term production decision.

2.5.2 Production subsidy

With a production subsidy, the price that the wind producer receives ($\widetilde{p_t}$) equals the market price in a given period (p_t) plus fixed subsidy s per kWh: $\widetilde{p_t} = p_t + s$. The objective of the wind power producer becomes:

$$\max_{\{q_{wind,t}\}} \quad \Pi_t = (p_t + s - c_w) q_{wind,t} \quad \text{subject to} \quad q_{wind,t} \leq \sigma_t q_{wind}^{\max} \tag{17}$$

The first-order condition eq. (13) is replaced by

$$p_t + s = c_w + \lambda \tag{18}$$

The production subsidy provides an incentive to produce even with negative prices (if the capacity constraint is not binding), until $p_t = c_w - s$. In this case, there is less incentive to adjust the production of wind power to market conditions than in the case with an investment subsidy.

2.5.3 Fixed price

Wind power production is always remunerated with a fixed price $\widehat{s}$, regardless of the market price. The objective of the wind power producer becomes:

$$\max_{\{q_{wind,t}\}} \quad \Pi_t = (\widehat{s} - c_w) q_{wind,t} \quad \text{subject to} \quad q_{wind,t} \leq \sigma_t q_{wind}^{\max} \tag{19}$$

The first-order condition replacing eq. (13) is

$$\widehat{s} = c_w + \lambda \tag{20}$$

As long as $\widehat{s} > c_w$, the wind power producer produces at the maximum available capacity all of the time: $q_{wind,t} = \sigma_t q_{wind}^{\max}$. There is no incentive to limit wind power production, regardless of the market price.

3 Data and assumptions in the numerical model

The numerical model developed to quantify the effects of different support schemes to wind power is populated with current data from Western Denmark.[17,18]

The distinct weekly pattern in power demand, as shown in figure 1, invites for simultaneous optimization over a week, followed by the next week, and so on infinitely. The numerical model therefore assumes simultaneous optimization over a week in the context of an infinite number of weeks.[19] In other words, the numerical model simultaneously solves for the optimal power production in each hour of a week ($t = 1, ..., 168$), assuming that this week is followed by an identical week *ad infinitum* (that is, the terminal condition assumes that demand after Sunday night is equal to demand on the preceding Monday).[20]

3.1 Demand

Demand is fixed and varies according to a predetermined profile, as shown in figure 1. Data from a week in January 2006 is used to specify demand. Electricity demand is higher in winter than in summer in Denmark. Hence, for a given level of thermal capacity, it would be easier to accommodate a given amount of wind power production in the market than in a situation with low demand.

[17] Western and Eastern Denmark constitute separate electrical systems, with no direct connection between them.

[18] The model is developed in the GAMS programming language, using CPLEX/MIP solver (Brooke et al, 1998).

[19] This is different from Nord Pool, where the market is cleared simultaneously for each of the 24 hours of the following day.

[20] In reality, the next week is similar, but not identical due to seasonal variation.

Plant ID	Capacity (MW)	Fuel (production)	Fuel (Start-up)
1	410	Coal	Heavy fuel oil
2	400	Coal	Heavy fuel oil
3	380	Coal	Heavy fuel oil
4	625	Coal	Heavy fuel oil
5	350	Coal	Heavy fuel oil
6	350	Coal	Heavy fuel oil
7	300	Coal	Heavy fuel oil
8	400	Natural gas	Natural gas
9	240	Natural gas	Natural gas
10	50	Light fuel oil	Light fuel oil
11	2400	Wind	

Table 1: Power plants in the model. Source: Company brochures

3.2 Thermal power plants

The thermal power plants are characterized by a number of parameters in the model: age and technology, combined with fuel prices, determine the operational marginal costs and start-up costs of a plant. Capacity determines the upper limit of production ($q_i^{\max}$) for a power plant, while technical minimum production requirement determines the minimum production level ($q_i^{\min}$) of a power plant, once it is operating; typically $q_i^{\min} = 0.3 \cdot q_i^{\max}$ (Wood and Wollenberg, 1996).

The thermal power plants of Western Denmark that were available in 2006 are used in the model simulations; the plants are listed in table 1, ordered according to increasing operational marginal costs. The corresponding fuel and CO_2 prices are listed in table 3 and commented in section 3.3 below.

If plants are permitted to produce continuously, plants with the lowest marginal costs are chosen first. Thus, with the present data, coal-fired plants are preferred in a continuous production mode, while in a start and stop mode, gas-fired plants have an advantage. When demand increases or wind power production decreases from one hour to the next, production can be increased in power plants that are already running if they have spare capacity; otherwise, more plants must be started.

	Coal	Natural gas	Gas turbine
Capacity (MW)	400	400	50
Efficiency (%)	45	49	32
Operational marginal cost (DKK/MWh)	183	222	1048
Start-up: fuel cost of cold start (DKK/MWh)	79 100	34 900	5 200
Start-up: indirect cost (DKK/start)	453 400	294 000	18 800

Table 2: Production and start-up costs of selected power plants. The author's calculations

Which particular power plant is next started depends on the marginal costs, the start-up costs and the (expected) duration of the higher demand. If demand is high for only an hour or two, gas turbines are turned on (small units with low start-up costs, but very high marginal costs); if demand is high for a longer period, a larger coal- or gas-fired plant is turned on (with higher start-up costs, but relatively lower marginal costs).

Table 2 illustrates the significance of the start-up costs compared with the operational marginal costs for some typical plants: namely, a medium-aged coal-fired plant, a relatively new natural gas-fired plant and a gas turbine. The coal-fired plant is cheaper in continuous operation than the natural gas-fired plant, while the start-up costs of the natural gas-fired plant are lower than those of the coal-fired plant. The fuel cost of one start-up in the coal-fired plant is equivalent to the cost of producing at the maximum production level for about one hour (since fuel oil is used as fuel for start-up, not coal). When indirect costs are taken into account, the cost of a start-up in the coal-fired plant corresponds to about seven hours of production costs. For the gas-fired plant, the fuel cost of one start-up corresponds to the production cost for $\frac{1}{2}$ hour and the total start-up costs, including the indirect cost, to four hours of production costs. The gas turbine has much lower start-up costs than the other plants, but the marginal production cost is considerably higher. Therefore, the gas turbine is typically only used for relieving shortage

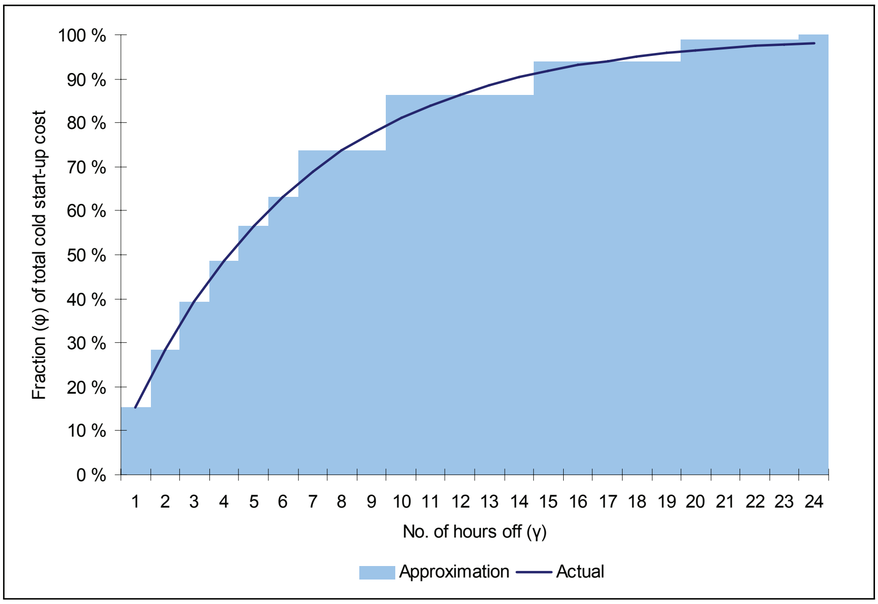

Figure 2: Time-dependency of direct start-up costs: actual and approximation used in the model

situations that last only a few hours and not for prolonged production.

The level of direct (fuel-related) start-up costs depends on how many periods the plant has been off before it is turned on again. However, while the start-up costs differ considerably depending on whether the unit has been off for one or two hours, the difference is much smaller than when the unit has been off about ten hours, and it is almost non-existent when the unit has been off for more than twenty-four hours. Therefore, in order to reduce the complexity of the numerical model, the direct start-up costs (eq. 2) are approximated with a stepwise linear function as illustrated in figure 2. The solid line shows the actual fuel costs (as a fraction of the full cold cost) of a start-up in every hour, depending on how many hours the unit has been off (measured by γ_{it}), while the stepwise linear function shows the approximation used in the numerical model.

Technically, all of the plants in the sample can start production within an hour. Therefore, other constraints that relate to a period shorter than an hour are not

Coal	63	USD/ton
Heavy fuel oil	285	USD/ton
Light fuel oil	585	USD/ton
Natural gas	12.5	EUR/MWh
CO_2	10	EUR/ton

Table 3: Fuel and CO_2 price assumptions

relevant to the model.

3.3 Fuel prices and taxes

Fuel and CO_2 prices determine the operational marginal costs and the start-up costs of thermal power plants and, consequently, the relative competitiveness of the plants.

The assumptions relating to the fuel and CO_2 prices are listed in table 3. The fuel prices are averages of 2006 levels, except for the natural gas price where a lower price, reflecting the historical level, is used. In evidence, the natural gas price was very high throughout 2006, making gas-fired power plants prohibitively expensive. The CO_2 price is slightly below the forward price (in 2006) for CO_2 allowances during the 2008–2012 period.

Even with the relatively low gas prices assumed, coal-fired power plants have the lowest operational marginal costs (recall that the plants are ordered according to the operational marginal costs in table 1). An increase in *all* fuel prices would only increase the cost level of all plants, not the relative competitiveness of individual plants. Considerably lower gas prices, higher coal prices or a higher CO_2 price would improve the competitiveness of gas-fired power plants and, by facilitating fuel switching from coal to gas, could also influence the results in a qualitative manner (Rosnes, 2005). Lower coal prices together with higher gas prices, on the other hand, would counteract fuel switching and increase the costs of emission reduction.

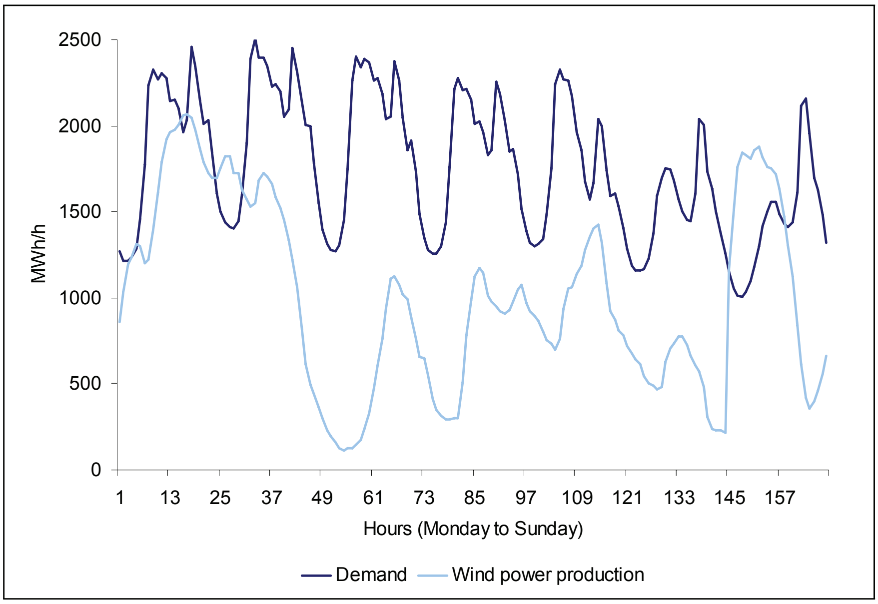

Figure 3: Wind power production (proxy for maximum available wind power) and net demand in Western Denmark throughout a week. Source: www.energinet.dk

There is no uncertainty, either about fuel prices or about the CO_2 price. This is realistic in the short term: day-to-day price variation is usually small.

3.4 Wind power

As explained in section 2.3, wind power production is limited not only by the nominal capacity of wind mills, but also by the presence of wind. Figure 3 shows actual wind power production in Western Denmark for each hour of a week in September 2006. The figure reveals that there is significant variation from one hour to the next: in some hours, production is close to the installed capacity of 2,400 MW; in some hours, it is close to zero. There is no systematic variation over the course of the day. Moreover, figure 3 also reveals that the wind power capacity is large, compared to demand (repeated from figure 1) and in some hours wind power production may exceed domestic power demand.[21]

[21] Note that actual production data may indicate wind power production that exceeds domestic demand, since it is possible to export the excess wind power in reality, a point discussed in section

The wind power availability, $\sigma_t q_{wind}^{\max}$, that determines the upper limit for production is calibrated in the numerical model by using the *actual* observed wind power production over a week in September 2006 (shown on figure 3).

The week in September 2006 was chosen as a sample week because it displays a relatively high level and high variation in wind power production (in a model with perfect information, a little variation would easily be accommodated by the market). At the same time, assuming demand of a winter week (i.e., high demand) facilitates accommodation of wind power in the market, while it would be more difficult to accommodate large amounts of wind power in a summer week (i.e., low demand). Accordingly, these two effects counteract each other.

The actual, rather than average, profile reflects the potential variation of the available wind power (while using average wind power production would level out the variation). However, the wind power producer is flexible within the range $[0, \sigma_t q_{wind}^{\max}]$ – the wind power producer can *reduce* production level from the maximum available level in each period (for instance when market prices are negative).

As wind power producers in Denmark were defined as having priority (i.e., the grid company was obliged to accommodate wind power whenever available) and received relatively high feed-in tariffs under the prevailing policy in 2006, the common belief of the market participants has been that wind power production was equal to the maximum available capacity. Therefore, the actual production provides a good proxy for wind power availability.

The marginal costs of wind power are assumed to be zero ($c_w = 0$), implying that the optimal production level is $q_{wind,t} = \sigma_t q_{wind}^{\max}$ for $p_t \geq 0$ with a lump-sum subsidy and for $p_t \geq -s$ with a production subsidy.

6. This excess production is truncated in the model simulations since total power supply cannot exceed demand. This is in line with the actual operation of the power market: the market operator can disconnect excess production in order to maintain balance in the market.

3.5 Subsidies to wind power

The present support scheme to wind power in Denmark is extremely complex.[22] A production subsidy that is added to the market price forms the basis of the support, but the subsidy level depends on the age and properties of the plant and the accumulated support provided to the plant over time. The highest production subsidy currently equals 270 DKK/MWh, with the total producer price capped at 600 DKK/MWh. In comparison, the average market price was 330 DKK/MWh in 2006, so the production subsidy provides a substantial mark-up on the market price.

In the simulations, I have used a production subsidy level $s = 100$ DKK/MWh that is in the lower range of the possible subsidies (but applies nevertheless to some categories of wind power).[23] The reason for choosing a relatively low subsidy was to allow for some flexibility in the model: obviously, the higher the production subsidy level, the more it resembles the fixed price. Therefore, the model results may overstate the wind power producer's willingness to adjust production.

In the fixed-price case, $\widehat{s} = 600$ DKK/MWh. Even though the current system for wind power support in Denmark does not include a fixed price, the fixed price is still topical in some other countries and therefore of interest. Besides, wind power has for many years had 'priority' over other power sources: that is, whenever wind power is available, it should produce at the maximum available level and the market operator is obliged to accommodate it in the system. This is equivalent to a (sufficiently high) fixed price.

The investment subsidy level does not influence the short-term production decision of the wind power producer and no investments occur in the short term.

[22] An overview can be found at www.energinet.dk.

[23] The renewables support scheme currently proposed in Norway includes a production subsidy of ca. 75 DKK/MWh to wind power.

Therefore, the exact level of the lump-sum investment subsidy S is immaterial. (The investment subsidy obviously affects investments in wind power capacity in the long term. The effect of different levels of wind power capacity is tested in the sensitivity analyses in section 5.)

4 The impact of different support schemes

Let me start by analyzing the market outcome under the three different support schemes to wind power: a lump-sum investment subsidy to wind power, a fixed price to wind power and a production subsidy.

4.1 Lump-sum subsidy to wind power

Lump-sum investment subsidies to wind power do not distort the production decisions of the wind power producer, as shown in section 2.5.1. Therefore, the lump-sum subsidy yields the optimal solution for production (within the limits of existing capacity). The wind power producer also takes into account the shadow prices of start-ups and shutdowns in the thermal plants, signalled via the thermal producers' bids and producer prices.

Figure 4 shows demand, production in thermal power plants and wind power production with lump-sum subsidy, as well as the maximum available wind power in every hour of the week. The prevailing pattern revealed in the simulation is that wind power production equals the maximum available capacity *most of the time, but not always* (figure 4). For a given operational status of all plants, it is always cheaper to produce using wind power plants than thermal power plants, because the marginal costs of wind power are always lower than any thermal unit ($c_i > c_w = 0$). However, if wind power production inflicts a change in the operational status of a thermal plant (a shutdown), additional start-up costs will occur in the future. In

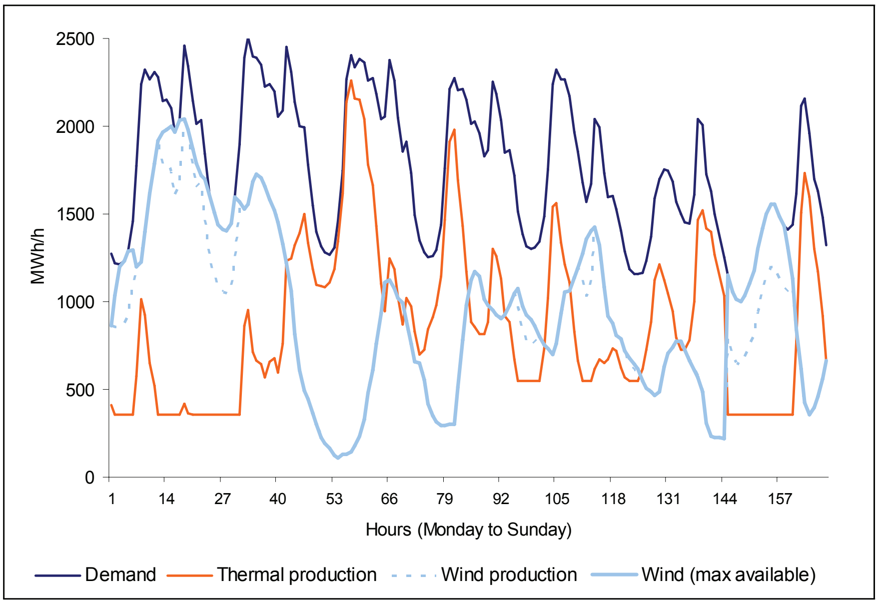

Figure 4: Net demand, wind power and thermal power production with lump-sum subsidy, base case capacity

this case, it is sometimes more profitable to reduce wind power production and let the thermal plants produce continuously instead (in spite of their higher marginal costs), in order to avoid the shutdown of a thermal unit. Shutting down a thermal plant for a short period is not justified because the start-up costs outweigh the cost savings of cheaper production.

This typically happens during low demand periods – nights and weekends – but not necessarily. Wind power availability varies considerably and the variation does not coincide with the variation in demand (as shown in figure 4). Since there is no systematic daily pattern in wind availability, situations with excess wind power production may also occur during high demand periods. In our example, wind power production is reduced even during some workdays (Monday and Friday), in addition to weekend days and nights. Wind power production is lower than the maximum available level for some 49 hours, that is, almost 30% of time. Total wind power production with the lump-sum subsidy is 8% lower than the maximum

	Thermal production (GWh)	Wind power production (GWh)	Emissions (1000 ton)	Production cost (fuel and CO_2) (mill. DKK)
Lump sum	146	150	108.5	32.6
Production subsidy	140	156	104.9	33.1
Fixed price	134	162	97.6	36.4

Table 4: Results of the numerical model, base case capacity

available.

The three cheapest thermal power plants produce nonstop, adjusting production levels between the minimum and maximum level. The other (more expensive) thermal plants start up and produce occasionally.

4.2 Fixed price to wind power

When wind power receives a fixed price, the producer does not respond to market signals (eq. 20). Receiving a fixed price $\widehat{s}$ per kWh, regardless of the market price, the wind power producer chooses to produce at the maximum available capacity ($q_{wind,t} = \sigma_t q_{wind}^{\max}$) all of the time, since $\widehat{s} > c_w = 0$. In order to maintain a balance between total supply and demand, the thermal power producers must adjust production accordingly – even turn off the plants if necessary.

In our example, wind power alone is able to meet total demand in some hours. All of the thermal power plants are 'forced' to turn off during these hours. In total, thermal power production is reduced 9%, compared with the case with lump-sum subsidies (see table 4 and figures 5 (wind power) and 6 (thermal power) for the results in both cases).

In addition to the reduction in total thermal power production, there is a shift between the thermal plants that produce in different hours. Some coal-fired plants produce considerably less, while others – smaller but less efficient – produce more. Gas-fired plants also produce more. These changes are due to the lower start-up

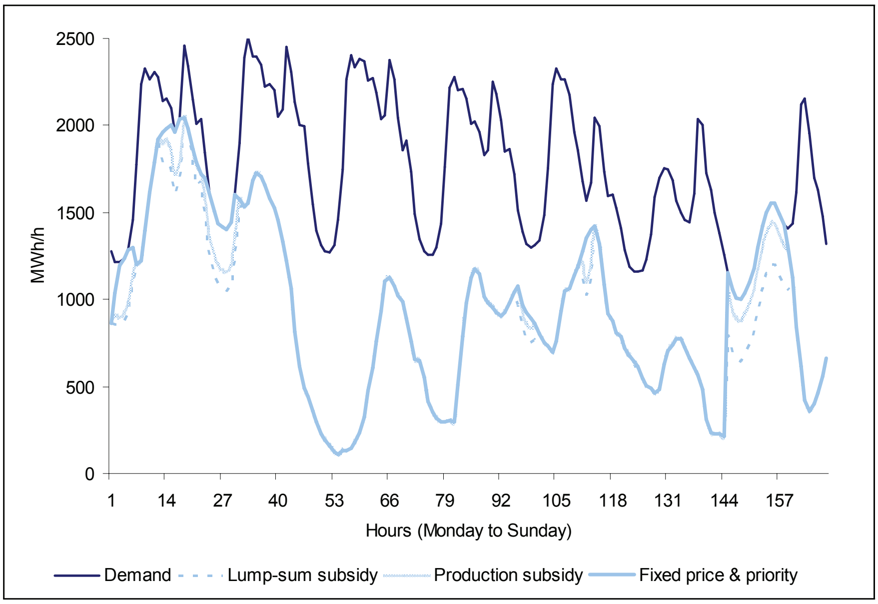

Figure 5: Wind power production with different subsidies, base case capacity

costs and minimum production requirements that outweigh the higher marginal costs in these plants.

Emissions stem from both production and start-up. Lower total thermal production obviously reduces emissions. In the case at hand, the effect of reduced thermal production outweighs the additional emissions from start-ups: emissions are 10% lower than in the lump-sum subsidy case (table 4). Fuel switching to gas-fired plants contributes to lower emissions, while the switch to less efficient coal-fired power plants contributes to higher emissions. All in all, however, emissions are reduced.

However, the remarkable result is that production costs are 12% higher, compared with the lump-sum subsidy case, even though the production level is 9% lower (production costs encompass both fuel costs and CO_2 costs). By forcing some plants to turn off and inflicting additional start-up costs, and by moving production to more expensive plants, production costs increase considerably. As a result, the emission reduction is achieved at considerable cost.

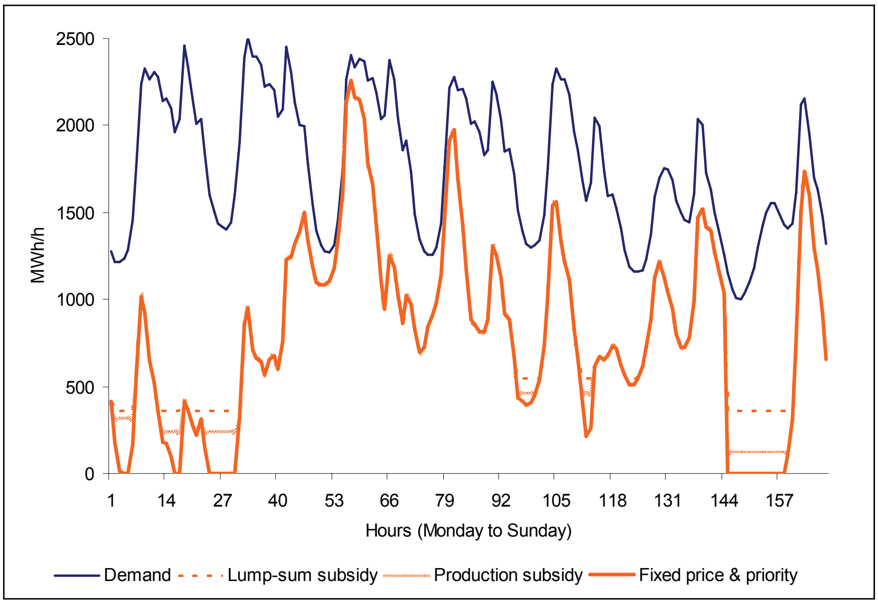

Figure 6: Thermal power production with different subsidies to wind power, base case capacity

4.3 Production subsidy to wind power

What happens if wind power obtains a production subsidy s per kWh? In this case, the wind power producer responds to signals provided by the market (eq. 18), but the signal is distorted by the subsidy. The wind power producer's bids reflect the willingness to produce until $p = -s$ (recall that $c_w = 0$).

In the present sample, the production subsidy of 100 DKK/MWh increases wind power production 4%, compared with the lump-sum subsidy (the results are reported in table 4 and figures 5 and 6). However, it does not yield the same result as the fixed price: production is still lower than with a fixed price and wind power production is reduced from the maximum available level in 42 hours.

By taking into account the shadow prices of the start-ups, the wind power producer accommodates thermal producers. Obviously, the start-up costs are so high that the thermal producers' bids are lower than $-s$ (the wind power producer's bid) in some hours. The results clearly show that it is profitable to reduce wind power in order to save start-up costs in some cases, even when wind power is subsidized.

Lower thermal production contributes to lower emissions: emissions are 3% lower than in the lump-sum subsidy case.

However, total production costs[24] are only 1% higher than in the lump-sum subsidy case and 9% lower than in the fixed price case. The flexibility to adjust to market signals gives considerable cost savings, even in the case of a distorting subsidy.

It is worth noting that the production subsidy level used in the model simulations is relatively low. Therefore, the market signals are distorted to some extent, but the outcome is similar to the one with lump-sum subsidy. A higher production subsidy would give incentives to higher wind power production and the outcome would resemble more the case with fixed price.

The model results indicate that the *optimal* wind power production is lower than the *maximum available* wind power production in many cases, even though the marginal costs of wind power are zero. By forcing some thermal units to turn off and thereby inflicting additional start-up costs later, and by moving production to more expensive units, production costs increase considerably. It is when wind power inflicts a shift in the operational status of a thermal power plant (a temporary shutdown) that costs increase considerably.

5 The impact of wind power capacity

It is reasonable to assume that as long as wind power constitutes a small share of total production capacity, it is relatively easy to accommodate in the market, despite

[24] The subsidy cost to wind power (i.e., the cost to the authorities) is not included in the production cost figure.

the possible distorting subsidies. The adverse effects will become more pertinent as the share of wind power in electricity production increases or is concentrated in some geographical areas. Sensitivities that test the impact of available wind power capacity confirm this intuition.

5.1 Easier to accommodate small amounts of wind power

The simulations presented above assume quite high wind power availability, compared to the annual average in Denmark.[25] There are times when the wind blows less, so available wind power capacity and hence possible wind power production is lower with the same capacity.

With only 50% of the original available wind power (but still the same profile over the week), the fixed price to wind power reduces emissions by 3% and increases costs by 6% compared with the optimum (the results are shown in table 5, labeled *low wind*, while the *base case* repeats these figures for the case commented upon earlier). The results confirm the qualitative effects of the original findings: a fixed price to wind power leads to suboptimal scheduling of power plants and higher total costs. Wind power production is higher and thermal production lower, but total production costs are higher when wind power receives a fixed price. The cost increase is relatively smaller than in the base case: with less wind power, it is obviously easier to accommodate wind power by adjusting the production level in the thermal plants, without turning them off altogether.

5.2 Boost of wind power capacity partly 'in vain'

One of the energy policy goals in Denmark is to double wind power capacity by 2025 (TRM, 2007).

[25] Nevertheless, let me emphasize that the base case above is based on actual data with existing wind power capacity.

	Thermal production (GWh)	Wind power production (GWh)	Emissions (1000 ton)	Production cost (fuel and CO_2) (mill. DKK)
Low wind				
Lump sum	215	81	163.7	45.6
Production subsidy	213	83	159.0	45.8
Fixed price	211	85	159.5	48.3
Base case				
Lump sum	146	150	108.5	32.6
Production subsidy	140	156	104.9	33.1
Fixed price	134	162	97.6	36.4
High wind				
Lump sum	71	225	51.8	18.5
Production subsidy	59	237	43.2	19.0
Fixed price	54	242	39.1	21.9

Table 5: Results of the numerical model

The results of the simulations with twice as much wind power capacity as in the base case confirm the effects found in the base case, but the effects are magnified (the results are reported in table 5, labeled *high wind*).[26] In this case, a fixed price to wind power reduces emissions by 25% and increases costs by 18%, compared to the lump-sum subsidy. A production subsidy (that distorts market signals to wind power, but does not remove them altogether) reduces emissions by 17%, but the costs increase by only 2%, compared with the optimal subsidy. Evidently, even a slight flexibility in wind power pays off.

It is also worth noting that increasing wind power *capacity* does not translate into an equal increase in wind power *availability.* Since the market must be in balance at all times, wind power production must be reduced if it exceeds demand and all thermal plants are turned off. As wind power capacity increases, situations where wind power production exceeds demand become increasingly frequent. Thus, some of the capacity increase is 'in vain'. Therefore, an increase in wind power

[26] The sensitivity with low wind, presented in section 5.1, may serve as an example for less wind power capacity as well. Although deinvestment is not a realistic option, it provides an example for how costs differ when choosing between different investment levels.

capacity by one kWh does not replace one kWh of thermal power – the increase in 'useful' wind power capacity is lower than the nominal increase. In the present case, the doubling of wind power capacity contributes little to 'useful' wind power production: maximum available wind power increases by about 50%, compared to the base case.

6 Alternative sources of flexibility

Two important sources of flexibility – trade and demand flexibility – were ruled out in the model simulations, mainly in order to make the analysis more clear-cut. The realism of these assumptions is commented upon below.

6.1 Trade

The model simulations assumed no trade with neighbouring areas. However, the trade possibilities already exist today: Denmark has interconnectors to Norway (a hydropower system), Sweden (partly a hydropower system) and Germany (predominantly a thermal system). The export and import possibilities provide additional flexibility to the power system: it is possible to export the 'excess' power that is caused by a sudden increase in wind power production or import power to avoid the start-up of a thermal power plant when a sudden calm period reduces wind power production. In a larger interconnected system, it is easier to adjust production level in the operating power plants without turning them off altogether. Connection to a hydropower system is particularly beneficial, since hydropower plants have practically no start-up costs.

The main reason to exclude trade in the model was to focus the analysis on the flexibility of thermal power plants. In the perfect world of the model, hydropower production would adjust immediately in order to accommodate both the varying wind power production and the variation in daily demand. The thermal power plants with lowest marginal costs would produce continuously, without any starts or stops, while other plants would remain idle.

Yet, the transmission lines are congested from time to time in reality. For instance, there were congestions between Western Denmark and Norway about 55% of the time in 2006, most of the time with congestion from Denmark to Norway. In these periods, an increase in wind power production cannot be exported in order to avoid the shutdown of a thermal power plant. Without additional investments, similar situations arising from transmission capacity constraints will become more frequent.

6.2 Flexibility of demand

These model simulations have assumed inelastic demand. Inelastic demand is quite a realistic description of the situation in Denmark in the very short term: most consumers' demand is virtually inelastic from one hour to the next, as most consumers do not observe hourly prices and therefore do not respond to these prices. Besides, the substitution possibilities are limited in the short term.

More flexibility on the demand side would clearly modify the results in the same way as trade with a flexible system and reduce the costs of thermal producers. However, increasing flexibility, for instance by installing two-way-communication,[27] would require additional costs. More flexibility can also be achieved by sending correct price signals to consumers – as long as consumers only see average (monthly) prices, there is no incentive to respond to hourly prices.

[27] Two-way-communication is technology that makes direct communication between the power supplier (distribution company) and consumer possible. By two-way-communication equipment, the distribution company can inform the consumer about price changes instantaneously and manage the consumer's power consumption. In this way, consumption reduction becomes an alternative to production increase.

7 Concluding remarks

The aim of this paper is to show how the costs of wind power integration in an inflexible power system and emissions from the system depend on the subsidy design to wind power. The existing system consists of thermal power plants that are inflexible in the short term because of start-up costs. Three subsidy schemes to wind power are studied: a lump-sum investment subsidy, a production subsidy per kWh (a mark-up on market price) and a fixed price per kWh (unrelated to the market price).

The lump-sum subsidy yields the optimal solution for production: wind power producers take into account the shadow prices of the start-ups, signaled through the bids of the thermal power plants. When wind power is optimally scheduled, it is sometimes profitable to reduce wind power production in order to avoid the shutdown of a thermal unit. When the production subsidy is designed as a mark-up on market price, the market signals are distorted. With a fixed price, wind power produces at the maximum available level and does not take into account market prices or the impact on other producers. With low demand, the thermal power plants are forced to stop in order to maintain balance in the market. Accordingly, investment and production subsidies are not equivalent in the short term.

The results of the numerical model of a sample week show that in the base case, thermal production with the fixed subsidy is 9% lower than with the optimal subsidy, while production costs (fuel costs and CO_2 costs) are 12% higher. In other words, the same production level is achieved with considerably higher costs. Sensitivity analyses with higher gas prices yield similar results, but slightly higher costs.

The wind power capacity and availability profiles used in the model simulations are not hypothetical figures, but actual observed figures. Therefore, the results reflect the situation today and illustrate the challenges in increasing wind power capacity in the future. Typically, the additional costs increase with increasing wind power capacity. Clearly, it is easier to accommodate wind power when wind power capacity is small relative to demand. As long as wind power can be accommodated without a change in the operational status of thermal power plants, the additional costs are relatively low. The results indicate that the incentives to adjust wind power even slightly would pay off: a small reduction in wind power often saves considerable costs. In other words, flexibility has a high value. The larger the market share of wind power, the higher the costs. The results of model simulations with different wind power data yield the same qualitative results.

Another important result is that increasing wind power capacity does not translate into a proportional emission reduction. With more wind power, situations when wind power exceeds demand, and hence cannot be utilized, will become more frequent. Even if wind power availability increases by one kWh, it does not replace one kWh of thermal power.

Modelling uncertainty about demand or wind power availability has not been feasible in the numerical model. Rosnes (2008), in considering a single power plant, has shown that higher uncertainty reduces the flexibility of a thermal power plant by increasing the threshold price for starting and reducing the threshold price for stopping. This indicates that uncertainty would probably increase costs even more.

It is somewhat paradoxical that production subsidies have been the most common support mechanism to renewables in Europe (COM, 2005), even though it is the high investment costs that prevent expansion of renewable capacity. It is probably fair to say that policies to support renewables have been characterized by politicians' determination to act quickly and investment volume has been in focus instead of investment efficiency.[28] Once in place, policies are often difficult to

[28]Germany has often been quoted as a showcase for effectiveness of feed-in tariffs in achieving

change due to lobbying activities. As the renewable technologies have traditionally had a tiny share of the market, the adverse effects were not particularly harmful. However, wind power is envisaged to be the main source of renewable energy in many European countries to fulfill the goal of 21% renewables in electricity production by 2010 (EC, 2001). In addition to Denmark, where wind power provided 23% of domestic electricity consumption in 2005, wind power production amounted to about 5–7% of total electricity production in countries such as Spain, Germany, Ireland and Portugal in 2005, and further expansion is planned; large wind parks are also planned in the United Kingdom and Sweden.

This analysis illustrates and quantifies the costs of integrating renewables in an inflexible power system. While the investment subsidy is shown to be unambiguously superior to other types of subsidies, the adverse effects of the other subsidies depend on the degree of flexibility of the existing power system. Hence, the design of the subsidy scheme should take into account both the characteristics of the existing system and the characteristics of the renewables capacity. An inflexible system should promote technologies that are flexible and reliable,[29] while a flexible system can afford promoting less flexible technologies.

Nonetheless, if wind power is the preferred technology in the inflexible system, it is important to promote flexibility. Flexibility can be achieved by technical measures or economic incentives. Measures to increase flexibility may involve increasing the demand response (either technically, by investing in two-way-communication, or economically, by exposing consumers to actual market prices) or on the supply side (investing in more flexible plants or increasing trade possibilities with other

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large investments in wind power. However, the German success is based on the very high level of feed-in tariffs. In other countries, with low feed-in tariffs, feed-in tariffs have failed to contribute to investments.

[29] This means reliable in the sense of being available when needed. As explained earlier, wind power is flexible, but not reliable – it is exactly the periods without wind that cause problems to the system.

regions). A larger system would increase flexibility per se, because it is easier to adjust production in active power plants without shutting down plants in a larger system. Further, trade with a more flexible system that can easily adjust the production level (like hydropower) is even more beneficial. However, these measures to increase flexibility require further investments that add to costs, in addition to the subsidies to wind power.

An economically sound subsidy design that does not distort the production decision of wind power and promotes flexibility in wind power production may be the cheapest way of integrating wind power.

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The thesis consists of an introduction and three self-contained essays. The essays investigate how climate policies – primarily intended to have long-term impacts – influence the power markets in the short term, and how the impact depends on the flexibility of the power system.

Essay 1 analyzes how the optimal production decision of a single fossil-fueled power producer is influenced by climate policies. The results indicate that if the power producer is inflexible due to start-up costs, then threshold prices for starting and stopping deviate from the producer's marginal costs. Further, climate policies change the threshold prices and the flexibility of the producer. Higher power price variation (as a result of the expansion of wind power capacity) reduces the flexibility of the producer, while a CO_2 cost (as a result of an emission trading system) increases the flexibility. If the CO_2 cost is coupled with higher power price variation due to more wind power, the positive effects may be reversed as the two policies have opposing effects.

Essay 2 studies how the effects of introducing a CO_2 cost in a power market depend on the flexibility of the whole power market. The results suggest that effectiveness (in terms of the achieved reduction in emissions) of a given level of CO_2 cost indeed depends on the flexibility of the power system: a lack of flexibility may either facilitate or counteract emission reductions in the short term. For some CO_2 cost levels, an inflexible system yields a higher reduction in CO_2 emissions than a flexible system, while for other CO_2 cost levels emissions are higher in the inflexible system.

Essay 3 analyzes how different subsidy schemes to renewables influence short-term wind power production and the interaction between wind power and thermal power plants. The main conclusion is that flexibility is crucial for the costs of wind power integration: if thermal power plants are inflexible, subsidies to wind power should strive to increase the flexibility of the market by passing market signals through to wind power. Investment and production subsidies are not equivalent in the short term.

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