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# Overview of investments in electricity assets

**by**

**Frode Skjeret**

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## PREFACE

This current paper gives a brief outline of the literature on investments in electricity markets. The focus is particularly on the relationship between investments in transmission and generation, and on the Norwegian electricity market, where the system operator owns the transmission grid. The Norwegian electricity market is special since one expects a large increase in production capacity in some regions (wind in the north and gas-fired in south-west), and at the same time, substantial increases in demand in other regions (electrification of oil-production). This may require large investments in transmission assets, in addition to the planned investments by transmission users. The paper discusses several contributions from the literature illustrating the complexities involved when system operators aim at planning investments ahead.

# CONTENT

# 1 INTRODUCTION

This note gives a brief (and partial) overview of the literature on investments in electricity markets and the focus is particularly on the interplay between investments in transmission and generation. Førsund (2007b) discusses several issues related to investments by a transmission system operator in a deregulated electricity market. The review is also written with an eye on the Norwegian context where the system operator owns the transmission grid. The Norwegian electricity market is also special since one expects a large increase in production capacity in some regions (wind in the north and gas-fired in south-west), but also substantial increases in demand in other regions (electrification of oil-production). The above mentioned arguments, coupled with the fact that the Norwegian electricity market is characterised by rather long distances between load centres and the sites for new generation capacity, imply that the system operator may face a considerable task.[1]

In this note, we are particularly interested in discussing the interdependencies between investments in transmission and generation. The focus throughout the paper is on the challenges faced by the Norwegian Transmission System Operator (TSO), Statnett SF. In order for Statnett SF to secure an efficient electricity market in both the short and long run, Statnett SF is required to assess how generation and demand will evolve in the future. This task is complex for several reasons. First, there are a great many options available to

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[1] Electricity markets were deregulated on the belief that the former regulatory regime gave incentives for investing in too high generation/transmission capacity. It was accordingly expected that the former system were characterised by too high a level of physical capacity, see for instance Averch and Johnson (1962). The deregulatory process had a number of features intended to reduce this alleged overcapacity, among them facilitate competition among producers, and to introduce transmission firms for incentive-based regulation, Bergman *et al* (1999). In the Norwegian case, it is oftentimes argued that the cause of overinvestment to a large extent stems from the energy-intensive industry pushing for low electricity prices.

solve the problems at hand. An efficient analysis implies that one regards the overall system as one, in many instances regarding transmission, generation and demand-side management investments as substitutes. In other instances, investments in generation clearly require investments in transmission. Second, the authorities aim at introducing a certain level of renewable electricity production capacity into the Norwegian electricity market. Thus, the current generation mix will be altered and a new production pattern will evolve as renewable technologies are put in place. Third, the problem is clearly dynamic in nature. A large investment in transmission affects the decision to invest in generation and vice versa. Thus, in order to assess the future demand for transmission services, one must assess the regional demand and generation patterns. However, the choices of transmission investments undertaken by the system operator will most likely play a role when entities determine the optimal location of generation or load.

Following the deregulation of electricity markets, there has been a reduction in the ratio of production capacity to demand in many electricity markets, Green (2007). Thus, deregulation may have achieved the goal of reducing overcapacity in the electricity industry. At the same time the reduction in physical capacity to demand cannot go on too long unless electricity markets reveal signs of stress.[2] Thus, while the deregulatory framework has been able to increase the efficiency by reducing over-capacity, it is still an open question whether the new regime is able to produce a sufficient amount of investments for maintaining an efficient electricity system in the future. An efficient electricity system should be governed in order to obtain both static and dynamic efficiency. Static efficiency is only achieved when the resources already in

[2] von der Fehr *et al* (2005) argues that the Nordic system are not yet in stress, but also adds that further demand growth and environmental requirements may lead to a more tight situation in the future.

place is used efficiently. Dynamic efficiency is only met when the physical assets (various types of generation and transmission in optimal location) are scaled to meet future requirements of the system, that is, static efficiency is met in later periods.

The rest of the paper is organised as follows. The next chapter reviews the literature on issues related to static frameworks for investments in generation and transmission. The third chapter discusses the literature on dynamic features of the investment process. This chapter also discusses interrelationships between transmission and generation investments, with a focus on investment in wind-power investments. The fourth chapter reviews the literature on system design. The point of departure of this discussion is the literature reviewed in chapters two and three.

## 2 STATIC FRAMEWORK

Electricity cannot be stored in an economically efficient way, and in contrast to most other markets, production must balance demand instantaneously and continuously. Imbalances may lead to a breakdown – not only affecting the agent that caused the imbalance – but the entire electricity system. What is more, only a small share of the demand side faces real-time prices and the economic incentives to adjust demand according to scarcity of electricity are slim. In order for the transmission operator to supply an acceptable level of *supply security*, it must make sure there is reserve capacity in the short run.[3] Supply security will therefore be taken to mean the ability of the system to meet demand given certain contingencies. In the long run, one must also secure *supply adequacy*. This term is related to the ability of the system to attract investments in generation capacity, but also the incentives for the transmission operator to invest in transmission capacity and various technologies on the demand side to make consumers respond to real-time prices (scarcity). Furthermore, supply security in the future requires planning for supply adequacy today. In addition, investments in both production and transmission capacity are in many instances best described as lumpy, and the cost of investing in these infrastructures are often very high. Plants are also in some instances expected to have a working life of several decades, and the pay-back time of investment projects may be considerable. What is more, once an investment has been put in place it is to a large extent asset (site) specific.[4] The next two sections introduce investments in generation and transmission, and discuss several aspects related to incentives for investments.

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[3] Thus, there must be an inventory (or stock) of electricity capacity readily available for the market. This inventory can be both production capacity and potential for dropping demand from the market.

[4] Many types of investments are inherently hard to move to other regions or in other ways sell off once in place. Other assets are less specific, but can still be characterised by various degrees of asset specificity making them hard to sell once in place.

## 2.1 Investments in generation

System operators aim to invest in transmission capacity in order to meet the future requirements of both demand and production. Since the generation side of the market is deregulated, one needs to consider how generating firms themselves contemplates about investing in generation capacity. There are several factors that need to be taken into account when trying to assess the future generation industry; below we discuss some of these.

### 2.1.1 Licensing

In order for an investor to be able to build a generation facility, one needs to obtain licenses from many public agencies. We will not go into the licensing issue here, however, the licensing process for investing in generation capacity may also be used as a tool for assessing the future generation activities, not only because one can foresee directly intended investment plans, but also because one may learn about profitability of various technologies in various regions.[5] This requires that the application for licenses actually describes the intentions of the investors. Further, the licensing process may be a valuable device for the system operator to govern the future investment process on the production side. This requires though that the system operator and licensing agencies are closely connected.[6]

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[5] The deregulation of the Norwegian electricity system has recently been evaluated in ECON (2007) and Hammer (2007), also in relation to licensing.

[6] ECON (2003) discusses the relationship between a transmission system operator (Statnett SF) and generators in an investment context.

### 2.1.2 Profitability

Assuming that licensing is not an obstacle, private entities subject to competition must find a project profitable in order to invest in new generation capacity, and will therefore look at expected future prices and costs when determining their optimal level of generation capacity. Cases where firms first invest in a certain level of production capacity (also production technology) and in later periods maximise profits taking the investment choices for given (during the working life of the investment) was initially analysed in Johansen (1972). Green (2007) discusses optimal investment in generation capacity using the framework of peak-load pricing (see Crew and Kleindorfer (1979) for an overview). He argues that, within the framework of peak-load pricing, there are three reasons for investing in capacity. The first is the case when the market has a lower than optimal level of capacity of a particular technology. Second, if a plant is allowed to reach the end of its physical working life, it must be replaced. Third, plants need not be allowed to reach the end of their working life in equilibrium. If a more efficient plant type becomes available it may be profitable to replace the old plant type with the newer and more efficient one. Green (2007) also discusses the case of optimal plant mix in a generation market, noting that efficiency is not only restricted to the optimal level of total capacity, but also the optimal mix of the various generation technologies.

### 2.1.3 Market rules and operations

In an ideal competitive market, the results of Green (2007) are expected to hold. However, in deregulated electricity markets, several market rules and operational procedures may affect investment decisions at various levels. We look into two sets of market rules herein, the operation of the wholesale markets and the organisation of the pricing mechanism.

Joskow (2006) discusses incentives for investments in generation capacity, and in particular two potential impediments to investments in generation capacity due to market rules and operational procedures.[7] Following Cramton and Stoft (2006), he argues that spot prices are not expected to be high enough to provide proper incentives for investors to invest in a cost-minimising portfolio of generation assets. This is referred to as the “missing money” problem. It is also argued that the rules governing the market may be used in a less than optimal way, for instance price caps are regarded as detrimental for investments. A part of such a reasoning may also be related to regulatory uncertainty about the future development of market rules, potentially affecting prices and also the expected behaviour of transmission system operators.

The second feature related to “*market rules and operations*” is the choice of how regional prices of electricity are determined. Prices are allowed to vary regionally in most deregulated electricity markets, and also access charges affect the cost of production according to where the facility is situated. The literature on regional pricing in electricity were initiated by the seminal work of Scwheppe *et al* (1988). Following their work, Chao and Peck (1996), Cardell *et al* (1997) and Bushnell and Stoft (1996) apply models of Schweppe *et al* (1988) to study various economic aspects of transmission constrained electricity markets. The main conclusion from these models is that regional price differences will give private agents incentives to invest in areas of high prices (most likely excess demand areas), and potentially make investments in load (for instance new industry) in low-price areas. These models focus largely on

[7] Volatile prices – a third topic mentioned by Joskow – are in some instances argued to reduce the amount of investment on the generation side of electricity markets. The example in Varian (1992), page 42 (and in most other textbooks in economics) illustrate that – since profit functions are assumed convex – uncertainty in prices will lead to a non-negative change in profits. As noted by Joskow (2006): “I do not think much of the argument that price uncertainty per se deters investment”.

how the price-mechanism in various markets (spot market, forward markets and ancillary markets) could best be organised in order to provide incentives for deregulated entities to behave competitively. Since any investment in transmission or generation (or demand) may affect regional prices, investors must also take into account the effect their investment has on prices. In Norway, zonal prices rather than nodal prices are applied and this has been analysed by Bjørndal and Jörnsten (1999) and Bjørndal *et al* (2002). Bjørndal *et al* (2002) also discusses various methods for congestion management and how these methods potentially affect prices and therefore the surplus of the various agents, including the system operator. They argue that the system operator may have incentives to affect the location of capacity constraints, thereby affecting system operator surplus.

Both arguments mentioned above (“*missing money*” and “*market rules*”) rest on three characteristics of electricity markets that may well lead to a less than optimal level of investments on the generation side. The above-mentioned impediments to investing in generation technologies are further examined in Joskow (2006) who investigates characteristics of i) certain production plants, ii) market operations, iii) demand side, and iv) flow of electricity over the grid. First, a fraction of the generation capacity in most thermal electricity markets are only used in periods of peak demand, thus the revenues required to cover both production and investment costs must be earned in only a few hours each year. These plants are naturally sensitive to the level of prices in the few hours when they are in operation, and price caps or public intervention in these hours (either on the demand or generation side) may reduce incentives to invest in these capacities. Similar arguments can be used when analysing incentives to invest in generation capacity in the Norwegian market, both in relation to windpower and hydropower production capacity. In a hydrobased system one may reason similarly in relation to storage capacity, since one optimally must store water for dry years occurring only rarely. Second, it is argued that electricity generation capacity in any one hour must be higher than the demand for electricity, in order to provide reserve capacity. Accordingly, the combined electricity market must carry an "inventory."[8] When the reserve requirements are violated, system operators take measures to increase the reserve capacity. If these measures are not properly arranged and applied, firms may not have incentives to invest in a sufficient level of capacity. For example, reserve production capacity owned and operated by the TSO can be used to affect prices. Reserve production capacity should only be used in extreme situations to deter system breakdown, and not in order to reduce prices in periods of peak demand. Third, real time pricing is in use only partially and individuals may not have the proper incentives for responding in situations of scarcity. Joskow and Tirole (2004) point up three reasons for why the demand side does not adjust consumption according to real-time prices in the wholesale electricity market. First, consumers may not have real-time meters installed. Second, if small consumers do have real-time meters installed, the cost savings from adjusting demand according to prices may be relatively small. Finally, some large consumers may find it very expensive to adjust its consumption in the short run, making them less flexible. Thus, short-term scarcity situations (in Norway, e.g. a very cold winterday) may not to a satisfactory degree reduce demand for electricity. Reliability of supply is therefore frequently in the very short term regarded as a public good (see for instance Hung-po *et al* (2005)). This problem may - in a hydrobased electricity system – also be relevant in the long term, when optimal storage of electricity must be determined months prior to when the scarcity situation sets in. Finally, electricity flows according to physical

[8] There are in principle two ways of carrying this inventory, either by purchasing generation capacity or by purchasing the right to close down consumption units.

laws and re-directing the flow of electricity comes at a high cost. Thus, the system operator is not adequately able to differentiate between consumers with varying degrees of marginal willingness to pay for electricity and reliability.

The general impediments for investment in generation capacity will not be studied herein per se; rather the implications for investments in generation will be discussed in relation to the planning of investments in transmission capacity. The general literature on investments in electricity is to a great extent related to thermal production facilities, analyses of hydropower markets are found in Førsund (2007a).[9]

### 2.1.4 Access charges

A fourth factor affecting the decisions of investing in generation capacity is the charge required for getting access to the grid. One particular concern when it comes to providing incentives for an efficient electricity market is how generators optimally should pay for costs related to connecting new production facilities to the transmission grid. If new generation capacity is connected to the grid, all regional prices – and all relative prices – are potentially affected, and may require additional transmission capacity. Access charges must therefore be arranged so that proper incentives for generation firms to invest optimally are provided.

This is of general relevance for transmission grids as new production facilities are required to meet increases in demand. This is also relevant since authorities in many countries aim to give incentives for increasing the use of renewable electricity technologies in production. Of particular interest is the focus on

9 See also Førsund (2005), Crampes and Moreaux (2001), Hoel (2004) and Garcia et al (2001).

providing incentives for the construction of windfarms located far from load centres. Access (to the grid) is a commodity that users of the grid should pay for. Since additional generation capacity affects the flow of electricity on the grid, there may be a need for strengthening the transmission network. There are also costs to society (externalities) that the investor (generation-firm) does not take into account unless an access charge regime is in place. One may therefore argue that the costs to the network consists of several cost components that must be paid for, either by i) the new generating facility, ii) the consumers or iii) all entities demanding network services. Assume that the total cost of connecting a new production facility ($TC$) is given by:

$$TC = C_L + C_S + c_R + c_L + c_{RD}.$$

$C_L$ gives the (local) fixed costs related to connecting the production facility to the network, while $C_S$ is the (central) fixed cost related to network upgrades required in other parts of the network. As the production facility is connected to the grid, and production takes place, this entity also affects the reliability of the network. This component is described by $c_R$. What is more, the flow of electricity on the network will be altered and the losses in the network is altered, this is given by $c_L$. Finally, $c_{RD}$ gives the costs related to redispatch. Note that only the fixed local investment cost is always positive. The debate on access charges for new generation facilities is often analysed via two extreme versions of access charges, deep and shallow access charges. The former type of access charge implies that the generator must pay $C_L + C_S$ up front and also $c_R + c_L + c_{RD}$ during the life of the production asset.[10] The other extreme – the

[10] A scheme similar to this is applied in the Pennsylvania-Jersey-Maryland electricity market, Hiroux (2004). Jamasb *et al* (2005) argues that there is an example in the Pennsylvania-Jersey-Maryland-market where the cost of connecting a new production facility to the network would equal the cost of building the generation facility.

shallow access charge – takes a very different view. In this case, only the local fixed costs of connection are paid by the new generation facility, while all other costs are covered by a system charge.[11] The following table illustrates the alternative access charges:

**Table 1: Access charging**

| | GENERATOR CHARGE | SYSTEM CHARGE |
|---|---|---|
| DEEP ACCESS CHARGE | $C_L + C_S + c_R + c_L + c_{RD}$ | |
| SHALLOW ACCESS CHARGE | $C_L$ | $C_S + c_R + c_L + c_{RD}$ |

If one assumes that the system operator is perfectly regulated, so that all charges are recouped either via producers or consumers (or both), the system operator may be indifferent between deep and shallow access charges. Two general results are readily available; first, when generators have to pay for all the connection costs, the access pricing regime provides high-powered incentives for localising production plants in regions where connection to the grid is favourable. Second, when the access charge is shallow, incentives are to a large extent rigged so that the cheapest production plants are being built. From a welfare maximising point of view, neither of the two extremes is necessarily desirable. On the one hand, shallow access charges may lead to an energy system with cheap electricity production entities in the wrong regions, while deep access charges may give expensive production facilities in favourable regions.

[11] A version of a shallow connection charge is applied in the Danish electricity market, Hiroux (2004).

If nodal prices could be expected to bring about optimal investments on the generation side, these could be used as approximations of variable charges, and fixed charges would be required to be recouped by the system operator, for instance via taxation. Jamasb *et al* (2005) discuss several issues related to the design of optimal access charges for distributed generation plants, taking both theoretical and political issues into account. Among the issues discussed are:

- ✓ Deep versus shallow access charges
- ✓ Forward looking access charges
- ✓ Locational signals for load
- ✓ Differentiation between energy charges, capacity charges and fixed charges

### 2.1.5 Lumpy investments

A fair share of investments in the electricity sector (both transmission and generation) can be regarded as large. In this section two issues related to large investments are discussed. Smeers (2005) argues that there is no common usable understanding of long-run marginal costs in the electricity market. He argues that cost allocation rules need not be the best way to proceed, and that such a framework need not provide the correct signals for investors looking far into the future when determining whether to invest in additional capacity or not. Using a model of integer programming, thereby allowing for lumpy investments in transmission, Smeers (2005) argues that the three criteria that are used when evaluating investments, i) economic efficiency, ii) cost reflectiveness and iii) non-discrimination cannot simultaneously be obtained. However, one should not take all lumpy investments or non-convexities as problematic. Only in cases where the size of the lumpy investments are large compared to the overall market (or regional market when transmission constraints are present) does this pose a problem. This is similar to the traditional microeconomic argument of a large set of competitive firms described by both fixed and variable costs of production. Each and every firm has a U-shaped average cost curve. However, although individual firm's supply functions are discontinuous, the discontinuities are irrelevant in a large market.

## 2.2 Investments in transmission

In order to secure static efficiency, the system operator needs to see to it that the current transmission assets in place are used optimally. This can be seen in conjunction with the ability of the system to provide supply security. However, the transmission operator must also invest in transmission capacity and facilitate efficient investments in production capacity, so that supply adequacy is maintained. This involves creating incentives for agents to invest in capacities necessary to meet future demand. Transmission adequacy is often taken to consist of two elements, sufficient capacity to balance load and generation given known and unexpected outages, and sufficient capacity in order for firms to sell electricity at marginal cost, thereby securing an efficient electricity generation market. Thus, the first component is related to reliability, while the second is related to merchant aspects of the electricity market.

In Norway, Statnett SF uses economic welfare measures to guide investments in transmission, in addition there are strict requirements to reliability, for a discussion on this, see Statnett (2007). However, it is difficult to separate these elements, since most investments in transmission over a congested corridor most likely reduces congestion, increases reliability and security, and also allow competitive firms to sell electricity at marginal cost.

### 2.2.1 Licensing and public resistance

Building transmission lines in a deregulated market is a task for investors (or public agencies), but there are communities that may be adversely affected by these investments, and in some instances investing in transmission is not regarded as an alternative at all. In economic jargon, this implies that transmission investments impose negative externalities on others. For instance, building a transmission line across a national park would most likely create a cost to society, in addition to the cost of the transmission line itself. Fischbeck and Vajjhala (2006) analyse similar issues using a formal analysis. They use four indicators to quantify the difficulty of siting large transmission projects (and also other large electricity projects like windpower farms), public opposition, regulatory roadblock (projects that affects several jurisdictions are regarded more difficult), environmental constraints (the physical and environmental aspects of the site) and system barriers (requirements from other parts of the electricity system may reduce the viability of certain projects). They use formal models to quantify difficulties related to siting large projects in the USA. When large projects create externalities, it will lead to public resistance to the project which in turn make the project a less likely candidate for investment. A similar reasoning is used when analysing the potential for windproduction along the coast of Norway, a large fraction of viable locations is located in the very north. This is partly due to the fact that this region is more sparsely populated than the coastline in the south, Statnett (2004a).

### 2.2.2 Transmission investment and transmission enhancement

A regulated transmission operator must see to it that a transmission investment is beneficial to society from a cost-benefit point of view, taking into account both economic and technical (security, reliability and viability) aspects of the investment. The general literature on investments in transmission capacity in electricity markets can roughly be divided into two categories, one focusing on the optimal regulation of transmission entities, while the other discusses whether transmission firms can be analysed using the economic model of perfect competition.

The first strand of literature argues that there should be independent regulated transmission operators investing in capacity, owning the lines and operating the network. It was also presumed that these institutions were to be regulated. Joskow and Schmalensee (1985) discuss various regulatory frameworks for the electricity industry. More recently, this literature has analysed various regulatory regimes required to have the regulated transmission operators behave as desired. Vogelsang (2005) discuss performance-based regulatory mechanisms and their effect both related to short-run and long-run efficiency.[12]

The second strand of literature takes the opposite view, that transmission firms can be regarded as competitive entities. This strand of literature assumes that competitive forces between transmission firms may provide sufficient incentives for transmission investments (this framework is referred to as the 'merchant transmission model'). Hogan (1992) studies how perfectly competitive environments may contribute to an efficient level of transmission capacity. Bushnell and Stoft (1996) study various ways to define transmission property rights and their impact on transmission investments, see also Bushnell (1999). Chao and Peck (1996) discuss how access and pricing policies affect efficiency in the market. Recently, this literature has been criticised by Joskow and Tirole (2005). They illustrate several assumptions underlying the models mentioned above – assumptions most likely relevant in electricity markets – making the merchant transmission model less usable. In fact, they argue that the

[12] For an overview over recent theoretical advances in regulatory theory underlying much of the practical regulatory frameworks in electricity, see Armstrong and Sappington (2007).

conjectures that profitable investments will be undertaken and unprofitable investments will not be undertaken may both be wrong.[13] Some of the factors listed in Joskow and Tirole (2005) are discussed below since some of the factors will also affect generators' decisions regarding investing in production capacity, thus public transmission firms may face similar difficulties.

*Lumpy investments*: Investments in transmission capacities are not continuous, but rather restricted to various (largely) fixed sizes. Turvey (1969) discusses marginal cost prices in such an environment, with illustrations from the electricity industry, while Turvey (2000) discusses access pricing in relation to lumpy investments (also in relation to electricity markets). Turvey (2000) discusses the relative merits of the American SDM-model (standard market design) and the British net-pool arrangement, arguing that the use of system charges in the British model makes this framework "scores highly with respect to long-run locational incentives."

*Asset specificity*: Once an investment in transmission capacity has been undertaken, investment costs can be regarded as sunk costs. Williamson (1983) introduced the concept of asset specificity and also defined four types, i) physical asset specificity, ii) site specificity, iii) human asset specificity, and iv) dedicated assets, where the first two types are most relevant here. The analysis of asset specific investments highlights the fact that cost before and after investing may differ. When investing in transmission capacities in order to meet expected demand for transmitting electricity from new investments in generation to load regions, hold-up problems due to asset specificity may arise.

[13] From the assumptions underlying the theories applied in this literature it can be shown that i) profitable investment, satisfying network constraints, will be undertaken and ii) unprofitable investments will not be undertaken, see Joskow and Tirole (2005).

*Nodal energy prices may not reflect willingness to pay for energy and reliability*. Reliability of supply is to a large extent non-depletable in electricity networks and competitive market equilibria would most likely be held back by free-riding. Thus, reliability has public good characteristics and may therefore not be sufficiently incorporated in nodal prices.

*Network externalities may not be internalised in nodal prices*: When transmission capacities are added to an existing network, all flows of electricity are potentially affected and therefore also nodal prices (and price differences). Accordingly, investments in transmission impose externalities on all other agents (producers, consumers and other transmission owners). One way to overcome this problem would be to define a set of enforceable and tradable property rights so that investors internalise the effect their investments have on other agents. The optimal organisation of such property rights – and whether they can induce a welfare optimising outcome – is currently debated in the literature.

*Transmission capacity is stochastic*: The potential capacity of a line is determined by reliability measures (like N-1, N-2 or probabilistic tools). This implies that the potential flow over a line is determined by the probability of failure in other parts of the network or the potential failure of generation capacities.

*Market power*: In the models above, all generators are assumed to behave in a competitive manner. In quite a few electricity markets market power among generators are seen as an important impediment to efficiency.[14] Accordingly, prices would not equal marginal cost of production. In relation to the debate on

[14] See for instance Green and Newbery (1992), Amundsen and Bergman (2002), von der Fehr and Harbord (1993) and the references therein. Skaar and Sørgard (2006) and Johnsen (2001) discuss market power in the Norwegian electricity wholesale market.

investments in transmission, market power is important since low transmission capacity between regions may increase regional market power exertion.

*System operators may have discretion to affect transmission capacities*: System operators may have substantial leeway for affecting transmission capacity. In real electricity markets, system operators may reduce capacity on a transmission line due to congestion in another part of the system. Further, in extreme situations system operators may i) add to production and/or reduce demand. In Norway, the system operator has thermal production capacities ready for production the meet extreme situations. In some jurisdictions, system operators may also reduce the voltage-level, effectively reducing demand. Such measures may negatively affect incentives to invest in generation capacity if not handled properly.

The list above is used by Joskow and Tirole (2005) in order to illustrate how private transmission firms may not find it optimal to invest in the desired level of capacity. Regulated public transmission firms may face similar problems when choosing among alternative transmission investments and the above mentioned factors are later used in relation to the problem facing a TSO.

# 3 DYNAMIC FRAMEWORK

The above chapter studied investments in a static framework, this section reviews the literature on interrelationships between (and within) investments in transmission and generation in a dynamic framework. There are large variations in both demand and production in the short-run. These short-run variations may be altered in the long-run, as new production technologies are phased into the system, and transmission capacity to markets with different mix of generation technologies are added. Investments in generation facilities may change the ratio of production to demand significantly in one region, demanding increased export capacity from that region, or alternatively, relieving congestion. Public policies toward renewable technologies may add to variations in regional production-demand ratios, not only by contributing to investments in generation capacity in one region, but also by reducing incentives for investments in other regions. If the subsidised technologies are intermittent, one may also expect that the short-run variations in production increases, also leading to differences with respect to regional growth rates in both demand and production capacity. Below, dynamic aspects related to both investments in generation and transmission are discussed in relation to the recent literature on introducing intermittent technologies, in particular, the effects of introducing wind power in electricity markets.

## 3.1 Dynamic issues related to generation investments

Any additional generation capacity connected to the network will to a certain extent affect both the price of electricity, and the flow of electricity on potentially all transmission lines in the grid. Thus, investments in generation in one region may affect incentives for investment in generation in other regions as well, and, what is more, investments in generation capacity may trigger investment in transmission capacity. The literature is to a large extent focusing on integration of wind, and the discussion below is therefore primarily on this topic.

### 3.1.1 Between generation assets

When a large amount of renewable production capacity is introduced into any electricity market, it is expected that the production mix changes.[15] In the long run it is expected that efficient technologies displace inefficient technologies. In addition, the various instruments creating economic incentives for renewable technologies (e.g. subsidies) may contribute to a similar effect. Accordingly, in the long run renewable technologies potentially to a certain degree crowd out existing technologies, thereby altering the technological composition of the generation side, see Green (2007) for thermal technologies.

There is a range of modelling tools available for analysing the impact of wind integration into electricity markets. Several research communities are working on these issues, herein we have chosen to focus on the Danish WILMAR-project since this project also allows for hydrobased production. The WILMAR project at Risø National Laboratory, see Ravn (2006) for documentation, is a modelling devise coupling a short term market model with a long-term model taking into account long-run market characteristics. The short-term model takes into account the fluctuations in windpower production and unpredictability of wind. The long-term model is a framework for determining optimal use of water over a year, in combination with other technologies. This part of the model studies the market on a weekly basis (52 weeks), where inflow of water into reservoirs, variations from other energy sources (CHP, wind and unregulated

[15] Wind-power production entities are oftentimes regarded as uneconomical in a competitive power market, that is, the large investment costs coupled with the expected lifetime of a wind-mill will not necessarily make investments profitable at current price levels. However, most countries currently aim at reducing $CO_2$ emissions, and regard wind-power as an alternative to attain this goal, thereby using various mechanisms for supporting investments in renewable production capacity.

hydro) and load are taken into account. The WILMAR model also takes into account geographical restrictions on the flow of electricity. A range of recommendations related to various issues emerged from the WILMAR-project, for instance recommendations related to:

- ✓ Use of transmission capacity
- ✓ Demand and provision of regulating power
- ✓ Rules for imbalance settlements

Other modelling frameworks are also applied in the literature on wind integration in electricity markets. Müsgens and Neuhoff (2006) apply a numerical model to analyse long-term investment behaviour for the German electricity market. They find that the system costs increase as the market approaches the capacity limit (peak demand). The focus of their analysis is on the additional requirements on ancillary markets needed in order for the electricity markets to operate efficiently. Neuhoff *et al* (2006) apply a similar model to Müsgens and Neuhoff (2006) analysing how the spatial correlation and variability of wind and congestion affect optimal investments on the generation side of the market. They conclude that providing locational price signals to generators is important for minimising the overall costs of the electricity system. They use the British electricity market to study the effect of integrating wind in Scotland, and transmitting electricity to southern parts of the island. Accordingly, one expects the introduction of renewable intermittent generation facilities to alter the technological composition of the system, thereby also the total production costs. In the Norwegian case, a large scale introduction of windpower production capacity may affect the incentives for both energy and effect capacity.

Since the potential from wind production is highest during the winter-period, one may expect that the incentive for investing in additional storage capacity may be reduced (*cet par*). Holttinen (2004) illustrates that optimal use of storage capacity may fall in regions where large investments in windpower production take place. Thus, a negative correlation between windpower production and temperature between seasons (winter and summer), may reduce the incentives for investing in hydrobased energy capacity. However, the consequence for (hydrobased) effect capacity is not known. As noted above, there is a negative correlation between temperatures and windpower production potential between seasons, and hydropower firms may have weakened incentives to invest in effect capacity. Another effect may also be present; a positive correlation between temperature and windproduction within the winter-season may reduce effect capacity during peak-demand hours (very cold winter day and no wind). Thus, prices may be expected to increase a lot in these hours if a large fraction of windpower production is installed, creating incentives for investing in effect capacity also by hydrobased production entities. Results in Holttinen (2004) indicate that this latter effect may be positive, thus as load increases due to a fall in temperatures, there is also a fall in wind production.

### 3.1.2 Between generation and transmission assets

Investments in generation may affect costs of operating the transmission system in at least two ways, long-term costs related to investments and short-term costs related to system operation. Revenues from access charges should exactly match the costs from investments and system operation.

*Long-run implications*:

Investments in generation capacity in the grid may require investment in transmission capacity, either directly to the region where additional generation capacity is connected to the grid, or indirectly in other parts of the market due to changes in the flow of electricity that the additional generation facility brings about. Large additions in generation capacity (especially new technologies) may also lead to changes in the investment decisions for both production and load in the grid potentially requiring changes in the transmission system.

Further, investments in windpower are – in the Norwegian case – most likely to take place in regions of excess production and there may be a need for investment in new capacity to bring the electricity to regions of excess demand. Windpower may also alter the production pattern over the day and the season, necessitating investment in transmission capacity in some parts of the network. E.g. when adding wind-production in Mid-Norway, there is also a need for upgrading the regional grid in this region, see Statnett (2004b). Thus, generation facilities in this region, may improve the energy balance, but will at the same time add to the need for upgrading the local network. Also, when upgrading parts of the transmission network in Norway, it may be optimal to also upgrade transmission lines in Sweden, see for instance Statnett (2006).

When investment in generation requires investments in transmission capacity either from the region where the new production capacity is added or in entirely different parts of the network, there are economic arguments for the investor to also pay a fixed access fee for using the grid. As the network investment caused by the additional generation capacity increases, one may argue that so should also the fixed access fee.

*Short-run implications*:

When there are public policies providing incentives for introducing intermittent technologies, one may expect that these technologies partially crowd out non-subsidised technologies. However, there are still limits to the integration of intermittent technologies due to short-run considerations (see for example

EnergyLink (2005) and OECD (2005)). Four issues related to short-run system costs to intermittent technologies are discussed below.

*Short term variation in wind farm output*: When there are large variations in wind production – in periods ranging from minutes to hours – there must be commensurate changes in other production facilities in order for production to meet demand. Porter *et al* (2007) states that: "wind generation can be predicted with about 90 percent or greater accuracy one hour ahead, with 70 percent accuracy nine hours ahead but only 50 percent accuracy 36 hours ahead." However, the variability of output from wind-farms is less variable than the variability of output of individual windmills. Furthermore, Holttinen (2004) demonstrates that wind variability of production from windpower plants falls as the region under consideration increases.

*Clustering of wind-farms*: A problem related to the above issue is the clustering of wind-farms and also that many of the proposed wind farms are located far from load regions. The clustering of wind farms potentially amplifies the problem of production variations and put further pressure on existing transmission capacity. Porter *et al* (2007) find that the increased system costs from wind integration are negatively related to the transmission capacity into adjacent markets and also negatively related to the flexibility of the existing reserve capacities. Thus, smaller electricity markets may have less potential for integrating large-scale wind generation. This is a concern in New Zealand, where there are two markets (north and south island), connected via a HVDC transmission line, but with small reserve capacities in both markets, see EnergyLink (2005). At the same time, EnergyLink (2005) argues that the New Zealand market is fortunate to have easily regulated hydropower able to meet relatively large swings in output-levels from windfarms. This argument may therefore also be relevant for the Nordic region, and particularly for Norway.

*Frequency Management*: When a large amount of production capacity goes down, reserve production capacity must be able to replace lost production rapidly. This requires an increase in available production capacity (via reserve markets) or a larger fraction of load on interruptible contracts. Thus, intermittent technologies may put strains on the ancillary markets where large scale windpower is in place. However, Porter *et al* (2007) argues that ancillary markets are affected asymmetrically by wind-integration. First, wind integration (capacity of wind production to total production) of less than 20 % hardly affects the amount of reserves required to handle variations in the very short run (1-10 minutes). It turns out that wind gusts are uncorrelated, even to a large extent locally in these time frames, thus additional windpower production does not add to the reserve requirements. Second, reserves intended to handle variations in the slightly longer time horizon (10 minutes - 1 hour) increases with the amount of windproduction installed. This is so since windpower production may suddenly fall from a very high level to zero, and in some instances this is not known until a few hours before it occurs. In Norway and Sweden this is handled in the regulating power market, accordingly one may expect increased trading in this market. However, as the windpower production (as a share of total production capacity) increases, there is need for increasing reserve capacities in these time frames.

*Generation scheduling*: There are also difficulties related to swings in production in the medium term, that is, over the following day. The longer the period between bidding and production, the greater is the uncertainty for windproduction facilities. It is accordingly difficult to assess what production levels will be over the next day when a large share of wind power production is in place. In addition, as noted in the WILMAR project, using the N-1 criterion may give too conservative production predictions and the transmission capacity may not be used optimally. Moreover, since windpower production is higher during winter, there may also be reductions in optimal storage in hydrobased systems, see simulations in Holttinen (2004). If wind power production is large during the spring (snow smelting), there may also be losses from operating hydroproduction facilities due to spill (since there are minimum flow restrictions in rivers).

In relation to the debate on access charges, introducing time adds at least two complications. One problem may be classified as a *first-mover advantage*. In some instances, one particular investment in generation will not create sufficient changes in flows over the grid to invoke investments in transmission capacity. However, when some early investors have invested a sufficient amount of generation capacity, a later investor will have to pay for upgrade of the transmission system. Thus, a deep access charge make investors postpone investments hoping that other firms invest and pay for the transmission upgrade, while a shallow access charge has less of an impact on the timing decision for generators. A deep access charge may in such instances be biased toward a few large investments in production capacity, rather than many small. This is so, if the many small investors must get together to cooperate on paying the deep access charge. A proper access charge system must therefore take into account that a series of additions to generation capacity eventually requires investments in transmission capacity. Thus, one must see to it that early investors contribute to the system costs of adding generation capacity to the grid. The second problem can be named the *second mover advantage*. Once an investor has added generation capacity to the grid, and also paid for the transmission system upgrade, it may be the case that investors connecting to the grid in later periods does not cause sufficient amount of changes in the flow of electricity to invoke investments in transmission capacity. Thus, these late investors free ride on the investment of the first-mover, at least until there is an investment that once again will trigger investment in transmission capacity. Accordingly, a proper access charge regime will make late investors contribute to the payment of transmission investments that was undertaken to meet the investment by the first mover.

Changes in demand may also affect the demand for transmission services. Introduction of real-time metering and the use of alternative energies may affect both the level of demand and hourly (and seasonal) demand for electricity, and therefore also affect the demand for transmission, both in the short and long term.

Transmission investments take in many instances longer time to complete than what generation investment does. Kirby and Hirst (1999) have interviewed many industry experts and notes that "companies that build merchant plants are reluctant to reveal their plans any sooner than the regulatory permit process requires." Thus, one may argue that transmission operators need to be forward looking when determining not only the optimal transmission portfolios, but also optimal access charges for production and demand. This – coupled with site and physical asset specificity – suggests that tariffs for connecting to the grid should be forward looking.

Joskow (2005a) examines alternative institutional arrangements in relation to the governance, operation, and maintenance of networks. He also looks into investment in transmission capacity. He differentiates between two sources of transmission investment, opportunities to reduce congestion, losses, and investments rationalised by reliability criteria. He argues that "Reliability rules play a much more important role in transmission investment decisions today than do economic investment criteria as depicted in standard economic models of transmission networks," but also at the same time he goes on to write: "I argue that economic and reliability-based criteria for transmission investment are fundamentally interdependent. Ignoring these interdependencies will have adverse effects on the efficiency of investment in transmission infrastructure and undermine the success of electricity market liberalization."

## 3.2 Dynamic issues related to transmission investments

### 3.2.1 Between transmission assets

In general, transmission operators evaluate many alternative investment projects prior to conducting an investment. For instance, Statnett SF examines how to transmit additional electricity injections from northern Norway to southern Norway, at least two alternatives are viable, one is an upgrading of existing transmission lines in Norway, and the other is to add new lines to existing transmission corridors in Sweden, Statnett (2006).

Stoft (2007) analyses these issues using real-option theory. He assumes that in a market with growing demand, there are two alternative transmission investment opportunities, with line sizes 600 MW and 1,000 MW respectively. He goes on to illustrate that it is privately profitable to invest in the 600 MW transmission line early in order to meet demand. However, the savings from building a smaller transmission line early is smaller than the overall savings from building a larger transmission line later. He argues that – for society – there is a real option (with positive value) from waiting. One may add several features to this simple example; a larger network may include the potential to invest in different regions. While the above investment projects are classified as mutually exclusive, one may also add complementary investments to the model, that is, if investing in one transmission line early, one will most likely have to invest in enhancements in other parts of the network later.

As discussed above, the regional network may also be affected by investments in generation – and in cases where there are several options related to investment in transmission - the system operator should take costs of upgrading the regional network into account when determining which transmission project to choose. This is discussed in Statnett (2004a) related to introducing windpower production in Mid-Norway.

The transmission line connecting Norway and Holland, the NordNed cable, will also most likely result in a new price area in the southern parts of Norway. Thus, the investment in a transmission line affects the day-to-day market operations of the Norwegian electricity market. Since the transmission line is sufficiently large to create a new price area, one may believe that also prices over the day and season are affected. Accordingly, daily operations of power plants within this region are most likely altered, and consequently incentives to invest in various types of capacity are affected.

As discussed above, there are most likely several opportunities when it comes to determining which transmission investment to undertake. First, there is the location problem, then one must determine the level and timing of investment. What is more, as noted in chapter 2, investments are site specific and not easily reversed. Thus, one may argue that an optimal investment policy involves coming up with a sequence of transmission investments that will maximise the value of the portfolio of transmission investments. This sequence of transmission investments must trade off benefits and costs among a set of transmission investment projects and their optimal levels of each transmission project, the choice of location (or corridor) and optimal timing of investment. In addition, when looking forward, the transmission operator must also assess how entities on the generation side will be affected by the optimal transmission plan.

A similar example – but in another context – is provided by Gans and King (2000). They illustrate how one optimally could regulate a transmission firm to undertake socially desirable investments in transmission capacity over time by using the fixed and variable terms of a two-part tariff. They argue that it is possible give incentives to the transmission operator in order to invest in capacity in the correct period. A similar system could potentially be used by transmission operators in an access price regime to give incentives to invest in generation capacity.

### 3.2.2 Between transmission and generation assets

As noted above, investments in transmission capacity have impacts on investments in generation. Both reliability of supply and the potential for transmission constraints would affect generators profitability, either positively or negatively. Investments in transmission capacity affect all relative prices and most likely the expected level of prices in electricity markets. Also, optimal access charges for connecting to the grid will affect the decision to invest. Thus, generators must foresee investments in transmission when determining optimal generation investments. The planning regime that is in use by the transmission operator is thus an important tool for generators when determining how much to invest in a specific technology and in a specific region.

Increased transmission capacity may also contribute to increased reliability of the overall transmission system. As discussed in Joskow and Tirole (2005), this may reduce the uncertainty related to stochastic transmission capacity thereby increasing the incentives for investments in production capacity. As a consequence, investing in transmission capacity for enhancing reliability of the transmission network reduces the uncertainty facing generators thereby potentially increasing incentives to invest. What is more, transmission capacity affects market power exertion, most likely negatively. Thus, the potential of being capped from the market – as in Cardell *et al* (1997) – is most likely reduced when transmission investments are undertaken.

Sauma and Oren (2006) also study how investments on the transmission side potentially affect investments on the generation side. They use a three-stage model to analyse how transmission investments affect incentives for investments in generation capacity. In the first stage, investments in transmission is undertaken, then generating firms choose their optimal level of investments in generation capacity, and finally, the generation firms compete in the spot market for electricity, where the spot market is characterised by nodal pricing. One of their main conclusions is that investments in transmission capacity have potentially large distributional impacts. For this review this implies that investment in transmission capacity may well affect investment decisions regionally. Sauma and Oren (2006) applies their framework for the Chilean market (32 node system) illustrating that proactive planning differs from reactive investment decisions even in a three-period model of an electricity system.

Changes in transmission operator behaviour regarding the operations of the transmission system may also contribute to affect generation profitability. On the one hand transmission operators may have incentives to add to the production side in order to use the grid optimally in the short run. Statnett SF has for instance purchased production capacity to deliver electricity in the two counties Møre og Romsdal and Sør-Trøndelag. The transmission capacity between regions may also be set strategically in situations of peak demand in order for the system to be optimised in the short run. However, the short-run optimisation of the transmission network need not provide incentives for optimal investments in generation capacity in the long run. Even more, merely expectations of such price reducing (or capacity reducing) policies in the short run in hours of high prices may reduce incentives for investments. In addition, transmission operators may also affect demand and thereby prices in the market. Measures to remove certain load entities from the market during periods of stress, will reduce demand and thereby prices, at least regionally. As a final measure, some system operators reduce voltage slightly in extreme events. This effectively reduces demand and therefore prices. Generators that depend on a few hours of very high prices in order to be profitable may be adversely affected if such policies are not managed properly.

# 4 SYSTEM DESIGN

Historically, a central authority for a vertically regulated industry undertook system design in electricity markets. Deregulation made system design considerably more complicated, as actions in the new regime are determined locally – actions that potentially have an impact on the efficiency of the overall market. However, there is still the need for transmission operators to make plans for the optimal system configuration; both in order to secure an efficient market in the future, and to make public for other agents how the system will look in the future. In economic jargon, this would amount to constructing a proper "mechanism design".[16] Two major questions related to electricity system design have been reviewed in the current paper.

- ✓ To what extent will investment in production capacity (and capacity mix) be adequate?
- ✓ To what extent will transmission investments be well-planned?

Two requirements must be in place for electricity markets to produce incentives for both supply adequacy and supply efficiency, first that efficient short-run transmission operations and, second that suitable models for long run planning of transmission capacity are in place. Any modelling framework aiming at analysing optimal future grid investments will have to be based on one or more simplifying assumptions. First, due to uncertainties – and the potentially large costs of undertaking the wrong investment – there may be arguments for

[16] Mechanism refers to the rules, protocols and institutions underlying the economic interaction between agents. Three economists won the Bank of Sweden Prize in Economic Sciences in Memory of Alfred Nobel (for the year 2007) for their work on what has become known as mechanism design theory, Professors Leonid Hurwicz, Roger Myerson and Eric Maskin. As the magazine "The Economist" puts it: "Mechanism design theory aims to give the invisible hand a helping hand, in particular by focusing on how to minimise the economic cost of "asymmetric information"- the problem of dealing with someone who knows more than you do." Mechanism design can be taken as a three-stage process, where the first part consists of creating "incentive compatibility", second to make agents want to reveal their information "revelation principle" and finally to implement the chosen standard, "implementation theory".

postponing investments. Thermal capacity – operated by the system operator – in Møre og Romsdal may therefore be optimal, given that one take the real option of transmission investment (waiting) into account. Thus, due to real options ordinary net present value analyses may give a poor prediction for optimal investment sequences. Second, given the dynamic problem of planning ahead in electricity system analyses, the modelling of the problem at hand must necessarily be characterised by "closed loops," see Fudenberg and Tirole (1991) for closed and open loop equilibria.[17] When agents, producers or consumers (or even transmission operators in neighbouring countries) may act strategically, the problem facing the transmission operator may not unique solutions. This problem will affect system design for transmission operators since i) their investments affect decisions on both the demand and generation side and ii) investments in generation (or demand) may directly or indirectly trigger investments transmission capacity. Thirdly, as noted earlier, investments in transmission capacity is to a large extent site specific, and often takes longer time to complete than generation projects. These two features make investments in transmission capacity (potentially) subject to problems of hold-up. As a generating firm plan for a large-scale investment requiring large investments in transmission capacity, and as the transmission operator must act in advance due to long completion time of transmission projects, the transmission firm is running the risk of investing in a transmission line that will not be built. This is general hold-up problem described in Williamson (1983). Rents (welfare) from a specific investment can be described as the value of the investment from its

[17] For the current report, a closed loop equilibrium describes the case where, say, an investment by the transmission operator affects investment decisions by users of the network, and (closing the loop) the investment decisions by grid users affect the optimal investment decision for the transmission operator. Fudenberg and Tirole (1991) define closed loop equilibria as: "If the players can condition their strategies on other variables in addition to calendar time, they may prefer not to use open-loop strategies in order to react to exogenous moves by nature, to the realizations of mixed strategies by their rivals, and to possible deviations by their rivals from the equilibrium strategies.

current use (or in a planning framework, value from its intended use). If a transmission project is undertaken on the assumption that there will later be built generation facilities, its value stems from providing these new generation facilities access to load centres. However, once the transmission capacity is in place, its alternative use has almost zero value if the generation projects are not undertaken. Table 2 (next page) illustrates various examples from the literature relevant to the above-mentioned requirements, efficient short-run transmission operations, and suitable models for long-run planning of transmission capacity.

The table below should not be read as an overview of the literature on investments in electricity assets, rather it is one illustration of how one may classify various aspects when conducting analyses of investments in transmission capacity. Though, the table is not exhaustive, it illustrates problems in the literature considered as important obstacles when conducting analyses of transmission investments by a transmission system operator. Table 2 is accordingly an overview of a subset of the problems present when conducting analyses of electricity market design. In particular, transmission system operators must determine an optimal sequence of investments in transmission capacity in order to secure supply adequacy, thereby securing supply security in the future. This optimal sequence of investments is affected by the investments in regional production capacities and also investments affecting regional load. As illustrated above, investments in load and generation affects the demand for transmission services, potentially requiring investments in transmission. Further, these investments may also affect the need for ancillary markets required to secure reliability in the market. At the same time investments in transmission capacity most likely affect the optimal decision related to investing in load and generation capacity. Above, we have focused on how regional electricity prices and access charges affect the decisions to invest in generation assets. The first column of the table lists the overall problems of transmission planning and operations, while the second column lists several topics to the overall problems. The third column gives examples from the literature on the topics listed, while the final column lists the section (in this paper) where the topics is discussed.

**Table 2: Overview of issues discussed in the current paper**

| Overall problems | Topics | Examples from the literature | Section |
|---|---|---|---|
| Short-run system operations | Introducing new technologies | Neuhoff *et al* (2007) analyses spatial correlation and correlation of wind in relation to price signals | **3.1.1** |
| | | Introducing new technologies via transmission investments may alter operational procedures | **3.2.1** |
| | Physical attributes of markets | Joskow and Tirole (2004) discuss several aspects related to the demand side, e.g. real-time metering | **2.1.3** |
| | | Wind integration and its effect on ancillary markets are discussed in Holttinen (2004) | **3.1.2** |
| | Optimal market rules and operations | Operational procedures are thoroughly discussed in Joskow and Tirole (2005) | **2.1.3** |
| | | Production capacity handled by system operator is discussed in section 2.1.5 | **2.1.5** |
| | | Pricing mechanisms are discussed in Chao and Peck (1996) | **2.1.3** |
| Planning of long-run transmission investments | Regional prices | Regional prices (zonal) in transmission constrained systems are found in Bjørndal and Jörnsten (1999) | **2.1.3** |
| | Access charges | Turvey (2006) analyses the British and American system with relation to locational incentives for generation incentives | **3.1.2** |
| | | Jamasb *et al* (2005) discusses several aspects of access pricing for DG | **2.1.4** |
| | Optimal sequence of investments | Large-scale models are oftentimes used to analyse impacts of introducing wind generation | **3.1.1** |
| | | The WILMAR-project analyses several issues related to introducing windpower into hydrobased electricity markets | **3.1.1** |
| | | Joskow and Tirole (2007) discusses several aspects related to investing in transmission capacity | **2.2.2** |
| | | Sauma and Oren (2006) use game theoretical models to analyse investments in both generation and transmission | **3.2.2** |
| | | Stoft (2007) analyses investments in transmission using real option theory | **3.2.1** |

## 4.1 Electricity system design

Above, it was demonstrated that there are a great many issues involved when deciding on investing in either transmission or generation in electricity markets. Chapters 2 and 3 illustrated that there may be substantial interrelationships between various investment projects when investing in a physical asset in electricity markets. Table 1 above gives an overview of the literature analysing efficient investments in transmission in relation to the topics discussed in the current paper. Most of the analyses listed above focus only on a few aspects related to the investments. There are a great many ways to describe the process of 'electricity system design', the discussion below is based on Wu *et al* (2006), see also figure 1 on the next page.

Market design in large electricity systems is a formidable task. In the following we borrow the terminology of Wu *et al* (2006) to review literature related to system design in deregulated electricity systems. They argue that transmission expansion planning involves two interrelated tasks, the process of transmission investment and the process of transmission planning.

- ✓ *Transmission investment* involves the analysis of transmission expansion candidates in order to assess the economic viability of the projects. For a public entity, this would involve undertaking an economic cost-benefit analysis of the project.
- ✓ *Transmission planning* is the assessment of technical aspects of the investment. This process also involves considering system reliability, and economic and environmental effects of the transmission project.

When undertaking cost-benefit analyses for choosing among transmission projects one needs to analyse all economic and technical aspects of the investments analysed. The figure below illustrates one possible way of considering transmission planning in deregulated markets. We first discuss assessment of demand and generation, and then the development of transmission project candidates from this assessment. These transmission candidates must in turn be evaluated both using technical and economic analyses. Finally, we illustrate some complicating factors underlying any such analysis of optimal future transmission investments. As noted above, and as exemplified in Sauma and Oren (2006), the problem facing system operators is large and complex. Several features of the design of electricity markets (refer to table 1) affects the optimal decision related to determining an optimal sequence of transmission investment.

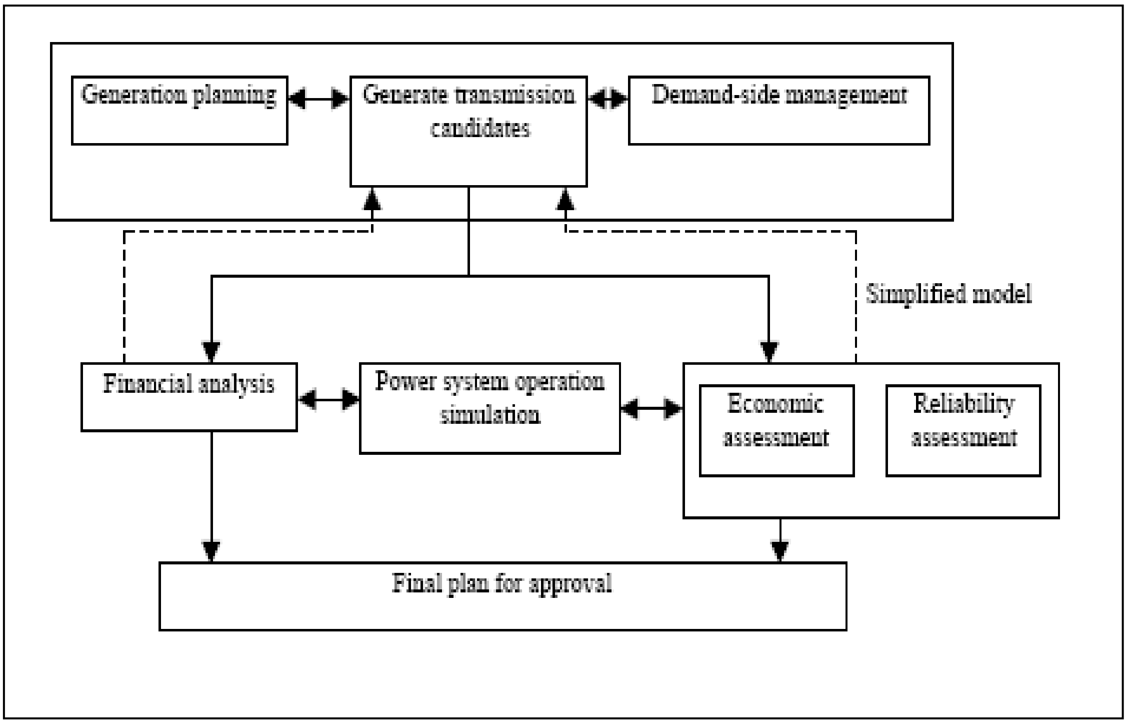


Figure 1: Copy of figure 2 in Wu *et al* (2006)

### 4.1.1 Assessment of demand

Demand for electricity changes over time, and the rate of change in time differs regionally. Already in the medium term, variations in demand over the day and year are uncertain as demand-side management may come to play an important role when consumers (also firms) determine their demand for electricity. This uncertainty most likely increases in the long term as regional consumption patterns may change significantly. Introduction of demand side management may also affect cost benefit analyses, via the need for transmission capacity.

Additional industry-demand or closure of industries in a region is not known in advance. In Norway, electrification of oil-production facilities and potentially closure of aluminium melting industry may give significant changes in flow of electricity in the network. Investments in demand response also affect the need for short-run system operation, as it is expected that this increases consumers' sensitivity to electricity prices.

### 4.1.2 Assessment of generation capacity

In a deregulated electricity generation industry, individual agents, though centrally controlled by authorities requiring concessions for investment, undertake investments in generation capacity. Decisions to invest in generation capacity are determined by both market-based price signals and regulatory institutions creating (dis)incentives for various generation capacities. Thus, regionally differentiated prices give dissimilar incentives for investments and access charges affect incentives to invest according to the region where the facility is planned. Finally, subsidies for renewable technologies bias incentives toward such technologies. When planning ahead, both in the medium and long term, one needs to take into account how these changes affect the regional production mix and the overall system. Furthermore, projections of future generation investments must also take into account expected investments in transmission capacity. As noted in section 2.1, a generator's ability to sell electricity is dependent on having as large production as possible during periods of high prices (demand). An investment in transmission capacity between high and low price regions may therefore give incentives for (dis)investments in generation capacity. Finally, the market rules applied (regulations and protocols) – and expected to be applied – may interfere with the incentives to invest in generation capacity (at a national level and regionally). For instance, markets for regulation power and the expected use of reserve power facilities may affect the incentives for investing in generation capacity to meet peak demand.

### 4.1.3 Transmission candidates

From the above mentioned projections one may obtain the expected flow of electricity among and within regions and thereby also uncover the need for transmission investment. However, as the problem is dynamic in nature giving rise to substantial problems when choosing among transmission candidates. First, as exemplified by Stoft (2007) (see section 4.2) one transmission candidate most likely affects other candidates. While some transmission candidates are clearly substitutes, there are also certainly transmission candidates that are complementary, where investing in one project also requires investing in another. In this respect it is important to find an optimal sequence of transmission investments. An aspect of transmission candidates – that in many instances can be argued to be complementary – is investing for security and reliability. An increase in transmission capacity between two formerly congested regions will most likely increase the potential use of other parts of the network, see section 2.2. When the Norwegian transmission system operator analyses the potential for integrating windpower in mid and northern Norway, six alternative plans are discussed, see Statnett (2004a). Some of these are stand-alone transmission projects, others also involve investments in other parts of the transmission network and/or in regional networks. Statnett (2004a) also takes into account how regulations on windpower output and flexible load affect the potential to phase wind into the grid. Second, transmission investments will also most likely affect investment decisions by generating firms and large consumers (industry).

### 4.1.4 Technical and economic evaluation

Having undertaken an assessment of expected future development of load and generation capacity, and also identified relevant transmission projects both technical and economic evaluation of these transmission candidates is needed. In the following, we first discuss the technical assessment, since many of the factors from the technical assessment also will be used in the economic evaluation. Statnett SF performs technical (electrical) assessment of the various transmission project candidates in order to quantify the costs and benefits to be used in a large system study. From these assessments, market model studies are often undertaken in order to simulate the properties of transmission candidates and their consequences on the existing grid and also the remaining power system. In addition, analyses are performed in order to quantify various aspects, such as security of supply.

Statnett classifies economic costs and benefits from transmission projects into several categories; reduction of congestion, reduction in losses, reduction in interrupted demand, and changes in transit costs. In addition, non-quantifiable costs are also taken into account when assessing the desirability of potential transmission projects. Externalities as those discussed in section 1.2.1, are included in these analyses (environmental externalities). Also, aspects affecting the overall efficiency of the electricity system are accounted for here. Below we briefly illustrate these issues.

*Technical assessment*

A transmission investment most likely affects the flow of electricity on the entire grid. Thus, there need to be a test of how a transmission candidate affects the overall network. At the first level, one need to test the future electricity flow in the networks, this can be used to infer both expected regional price levels and also expected flow across various transmission lines. Such system tests can also be used to assess the expected constraints that may come about in a constrained network in the future. Second, the technical assessment should also enable the system operator to infer reliability and security analyses of the expected future electricity system. However, such analyses will be difficult to undertake the longer the timeframe. First, the generation and consumption levels, and their regional composition will be harder to predict. Further, new technologies both on the demand and generation side have an uncertain effect on both price levels and price variations both on the national level and regionally. Thus, the need for transmission capacity is not easily inferred.

*Economic assessment*

Cost benefit analyses are used when analysing large projects in Norway, and when undertaking analyses of transmission investments, one needs to take into account consumer surplus, producer surplus and costs of system operation. Consumer surplus is determined by price and quantity effects, but also reliability, security, and the quality of electricity supply will be factors to take into account in cost-benefit analyses, and finally, externalities must be taken into account. Producer surplus is also affected by the price level, but with the opposite effect of consumer surplus. Just as for consumers, reliability and security must be included in cost-benefit analyses. Increased uncertainty about transmission capacity may affect generating firms negatively, and if there is a negative correlation between transmission capacity and price levels (demand), this effect may be substantial for generating firms. Transmission investments reducing the potential for market power exertion is, however, positive from society's point of view. Costs of system operation must also be included. First, long-run costs related to expected additional investments or enhancements, and second transmission investments will most likely affect the costs of system operation. Both costs of trading on the regulating market and changes in costs from purchasing reserve capacity may be affected by transmission enhancements.

Joskow (2005b) argues that most transmission investments are undertaken for reliability and security reasons. However, one may expect that investments that lead to reduced price differences also in most instances lead to increased reliability of electricity supply and also to reduced stochastic transmission capacity in other parts of the market. This is not always correct. Blumsack (2006) illustrates an example of a transmission typology that will actually lead to an opposite result, where there is a negative relationship between reliability and congestion. When investing in a transmission line (of the type 'wheatstone bridge') congestion may increase throughout the network. This result is also known as the Braess' paradox, the case where an investment connecting two new regions may lead to reduced transmission capacity. However, reliability of the network may increase if system operator uses a measure like the N-1 criterion. Further, Blumsack (2006) argues that these types of network configurations are quite common in actual power markets, and he notes that "awareness of these network structures is critical for the planning process."

## 4.2 Summing up the literature

This section gives an overview of the literature with the aim to point out some of the main challenges involved for transmission system operators seeking to minimise costs form network operations, and still meet requirements for security and reliability. Transmission system operators must both invest in an optimal portfolio of transmission assets, and give users of the network (producers and consumers) correct signals for production decisions in the short run and investment decisions in the long run.

The first problem – investing in an optimal portfolio of transmission assets are complicated for at least two reasons. First, the task of assessing future demand for network services by producers and consumers connected to the grid is complex. This stems from new investments by users of the grid. Both consumers and producers may invest in new regions, requiring investments in network capacity. In addition, users of the network may invest in new technologies at current locations, potentially affecting both the level and variation in demand for network services. Several modelling frameworks are used to analyse the demand for investments in transmission capacity, however, due to the complexity involved simplifying assumptions are required for obtaining a proper equilibrium. Consequently, the models referred to above are only able to analyse subset of the problems facing a transmission system operator. Second, just as long term investments by users of the network most likely affect the long run costs of maintaining an acceptable level of transmission services, short run costs related to running the system will most likely change. Intermittent technologies on the production side may affect the costs of operating ancillary markets negatively. In the text above, we focused on introducing windpower in electricity markets and the need to compensate for reduction in production due to decreased wind gusts. Investments by consumers (real-time meters and two-way communication) on the other hand, may reduce costs for overseeing the electricity system. Since assessing future investments by users of the grid is difficult, analysing how investments by users of the grid affect the short-run costs of running the transmission system is difficult as well. Also, transmission system operators are expected to minimise total costs of the transmission system, they must assess both long-run and short-run costs. As a result, analyses of short-run costs due to investments in new technologies most often use some sort of scenario analysis. The theoretical framework applied when modelling electricity systems, reviewed in the current paper, can be summarised under four headings:

- ✓ *Modelling the development in market structure*: In this type of analysis, the focus is on analysing the development of generation level, mix of generation technologies and transmission investments, taking into account public policies. See for instance Maddaloni *et al* (2007).
- ✓ *Modelling of short-run operations*: These analyses to a greater extent take the long run equilibrium for given, analysing impacts of changes in, say, generation mix on the short-run operations of the market. An example is given in Holttinen (2004).
- ✓ *Combining short and long-run analysis*. Some authors aim to bridge the above frameworks in one modelling framework. The WILMAR-project, referred to above is an example of this type of modelling.
- ✓ *Strategic interactions*: Some authors note that many agents in the electricity sector best are described as large, and may act strategically. These authors use game-theoretic models to analyse optimal investments in environments where these agents are able to affect price levels, see for instance Sauma and Oren (2006).

Recent analyses applies real option theory in order to understand the complexity involved when there is a portfolio of potential investment candidates and where the timing of investment is of importance. Miltersen and Schwartz (2004) illustrate how uncertainty along a range of dimensions can be combined into one model. As illustrated in the simple example by Stoft (2007), real option theory may well be used to study various aspects of transmission investments, in particular, this is the case when analysing a portfolio of investments where time is important.

The task of providing proper signals for investments among users of the grid is also complicated. First, there are clearly interactions among investments undertaken by the transmission operator and investments carried out by users of the grid. As illustrated in the text above, investments in new capacities may affect prices levels and price differences between two regions, potentially influencing grid users' decisions to invest. Second, the interaction between grid owners and grid users is regulated by the use of access charges.[18] In general, fixed charges are imposed on the users in such a manner that overall welfare loss is minimised, von der Fehr *et al* (2002) discuss these issues in relation to electricity networks. An investment may affect the profitability of investments in later periods, as the example in Sauma and Oren (2006). Thus, as noted in the text above, proper access charges should secure a proper sequence of investments. As evident from above, investments may also generate externalities affecting the desirability of investing in certain regions. Recent analyses focus on how to optimally finance the revenue deficit for the grid owner, three aspects are relevant:

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[18] Statnett SF is regulated according to a revenue cap, and is allowed to collect revenues from network users via access charges, restricted by the revenue cap. Social optimal charges imply pricing services for transmission to marginal cost, however due to the cost structure of transmission operation, marginal cost pricing leads to an income lower than the allowed revenue cap. This is because the regulatory determined revenue cap includes both fixed and variable costs from transmission operation. Accordingly, Statnett SF may therefore set access charges with both a fixed and variable component. The first component secures short-run efficient usage of the network by setting a price equal to marginal cost, and the fixed factor secures revenue adequacy for Statnett SF.

- ✓ *Differentiation of charges among grid users*: In order to minimise distortions, access charges are differentiated between both producers and consumers. There are also economic arguments for differentiating between users of the grid according to location and technology.
- ✓ *How to design charges that make allowance for lumpy investments*: As discussed in the text above, access charges must be designed to tackle problems related to first-mover and second mover advantages.
- ✓ *How to design forward-looking charges*: In continuation of the above, it is often argued that transmission system operators should provide signals for location of new investments by grid users. In particular, the system operator should seek to minimise the overall costs of the electricity system by using access charges to signal optimal locations of new investments.

Access charges should induce users of the gird to invest in the proper technology in favourable regions. Contract theory (see Bolton and Dewtriont (2005) for an overview) studies several problems related to access pricing relevant to the challenges noted above. First, this literature allows for contracting in time, a feature that seems to be of importance for investments in electricity systems. Second, this literature also allows for analysing contracting relationships in the presence of imperfect information (asymmetric information and unverifiable information), a feature that is relevant for investors in electricity markets. Thus, the use of contract theory, in combination with theories of access pricing, may well yield additional knowledge about how to design access charges that induce grid users to make socially desirable decisions.

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