Risk Management in Electricity Markets Emphasizing Transmission Congestion

by

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A thesis submitted to:

The Norwegian University of Science and Technology
Faculty of Information Technology,
Mathematics and Electrical Engineering,
Department of Electrical Power Engineering

in partial fulfillment of the requirements for the degree:
Philosophiae Doctor (PhD)

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Preface

This thesis is the result of a doctoral project at the Department of Electrical Power Engineering at the Norwegian University of Science and Technology. The work has been carried out during the period January 1999 to February 2004 including 14 months leave of absence where I worked as a Generation Planner at the Department of Electricity Portfolio Management and Trading, Norsk Hydro ASA. Parts of the research have been accomplished during a one year stay as a Doctoral Fellow in Harvard Electricity Policy Group at the Center for Business and Government, John F. Kennedy School of Government, Harvard University.

Financial support for the project was provided by the Research Council of Norway.

The thesis consists of eight papers that can be read independently. The papers involve transmission congestion risks, pricing of electricity derivatives, transmission pricing and investments, and risk management. The thesis has two parts. The first part is an introduction and review of literature related to the papers. It also summarizes the papers and their findings. Part two consists of eight research papers.

Acknowledgements

I am grateful for the supervision from Professor Ivar Wangensteen and benefiting from his knowledge about transmission pricing. I also appreciate the extensive freedom with which he allowed me to pursue my own research interests. Likewise, my co-supervisor Senior Researcher Birger Mo at SINTEF Energy Research shared his know-how in hydropower scheduling and risk management models. I would like to express my gratitude to Professor William Hogan for accepting me as a fellow in the Harvard Electricity Policy Group and for his supervision during my stay. I am also grateful for the advice from Professor Juan Rosellon at CIDE Mexico, and for our co-operation and discussions. Of the people working in the Harvard Electricity Policy Group I would particularly like to thank Assistant Director Ann Stewart for her advice, comments on my papers and discussions. A PhD colleague, Steven Anderson was also helpful and supportive.

I have benefited from comments on my papers from Professor Ross Baldick at the University of Texas at Austin, and from senior researchers Birger Mo and Anders Gjelsvik at SINTEF Energy Research. Additionally, Dr. Harry Singh at the Federal Energy Regulatory Commission was helpful with providing figures and charts. My colleagues at NTNU have also been helpful and supportive. From my time at Norsk Hydro and afterwards I would like to thank Market Analyst Tom Olaf Hammervold and Structural Analyst Morten B. Gustavsen for discussions and data. Similarly, Dr. Erik Tjøtta at Statkraft was also helpful in discussions. I acknowledge the editorial assistance from Stewart Clark, Assistant Professor at the Norwegian University of Science and Technology.

Finally, I would like to thank my parents and my brother for their support.

Trondheim, February 2004

Abstract

This thesis analyzes transmission pricing, transmission congestion risks and their associated hedging instruments as well as mechanisms for stimulating investments in transmission expansion. An example of risk management in the case of a hydropower producer is included.

After liberalization and restructuring of electricity markets, risk management has become important. In particular the thesis analyzes risks due to transmission congestion both in the short- and long-term (investments) for market players such as generators, loads, traders, independent system operators and merchant investors. The work is focused on the northeastern United States electricity markets and the Nordic electricity markets.

The first part of the thesis reviews the literature related to the eight research papers in the thesis. This describes the risks that are relevant for an electricity market player and how these can be managed. Next, the basic ingredients of a competitive electricity market are described including the design of the system operator. The transmission pricing method is decisive for hedging against transmission congestion risks and there is an overview of transmission pricing models considering their similarities and differences. Depending on the transmission pricing method used, locational or area (zonal) pricing, the electricity market players can use financial transmission rights or Contracts for Differences, respectively. In the long-term it is important to create mechanisms for investments in transmission expansion and the thesis describes one possible approach and its potential problems.

The second part comprises eight research papers. It presents empirical analyses of existing markets for transmission congestion derivatives, theoretical analyses of transmission congestion derivatives, modeling of merchant long-term financial transmission rights, theoretical analysis of the risks of the independent system operator in providing financial transmission rights, an analysis of inefficiencies associated with ignoring losses when utilizing area (zonal) pricing, and an application of an integrated risk management model on the power system of Norway's second largest hydropower producer.

The most important research findings include the following issues. First, Contracts for Differences in the Nordic market appear to be over-priced. Second, a merchant long-term financial transmission rights model is possible to realize in mathematical and economic terms. Third, by including the proceeds from a financial transmission right auction the independent system operator can issue a higher volume of rights because there is a relationship between the congestion rent, the proceeds from the auction and the payments to the financial transmission rights holders. Fourth, ignoring losses in the Norwegian area pricing, can lead to inefficiencies. Next, an integrated risk management model is applicable on large-scale power systems. Then, an overview is presented of different contractual arrangements that can be used to hedge transmission congestion risks. Finally, empirical data from existing financial transmission rights markets demonstrate how these markets work.

TABLE OF CONTENTS

1 Introduction

The analysis of transmission congestion risks and mechanisms for transmission expansion depends upon the specific market design. The transmission pricing method and congestion management procedures will be decisive for the risks that a market player is exposed to. Likewise, the institutional design of the system operator and its relationship with the transmission system are important in attracting new investments in transmission. This thesis focuses on the northeastern United States (US) market design with locational pricing and the Nordic market design with area (zonal) pricing.

1.1 Motivation

Risk management is complicated in a restructured electricity market. Moving from regulated markets with no or very low price uncertainty, the electricity markets are now facing liberalization and restructuring. Electricity prices are no longer determined by the regulator, but by the market. Experience from the Nordic and California electricity markets demonstrates that the prices may exhibit extreme volatility. An electricity market player therefore needs risk management procedures. Electricity can be traded as any commodity on power exchanges like Nord Pool and the European Energy Exchange. However, compared to the financial markets, many electricity markets lack liquidity, have tremendous volatility, exhibit non-normal price distributions, and have market incompleteness. In particular, transmission constraints and the non-storability of electricity present complications. Because of the specific electricity market characteristics, the risk management ideas developed for the financial markets are not directly applicable to the electricity market. Risks can be managed by using financial derivatives and integrated hydropower scheduling models. Risk management requires frequent monitoring and assessment of all relevant uncertainties, and knowledge of how these affect the market value of the power portfolio of the market player and its associated probability distribution. Given this information, the market players can make decisions according to their attitude to risk.

When supply and demand conditions change, market players experience volatile locational prices due to energy prices, transmission congestion and losses. To overcome problems associated with transmission congestion, financial instruments for hedging against locational price differences such as financial transmission rights (FTRs) and the Nordic Contracts for Differences (CfDs) can be utilized. These instruments can be a mechanism to share or mitigate risk. Transmission congestion creates a social welfare loss reflecting the opportunity costs of the transmission constraints. If the system operator collects the congestion rent, it could create incentives to manipulate dispatch and prevent transmission expansion in order to increase the rent. System operation is a natural monopoly and the system operator could redistribute the rents through a system of FTRs to those who are paying the transmission access charges to cover the fixed costs of the transmission network. The prime example of this implementation is the PJM (Pennsylvania-New Jersey-Maryland) market in the United States. Long-term FTRs can also be awarded to investors in small-scale transmission expansion projects.

The Nordic market has experience with restructuring since 1991 when Norway opened its electricity market to competition. In 1996, Sweden joined, followed by Finland in 1998 and Denmark in 1999-2000. Internationally, the Nordic power market is considered a success. The politicians, regulators and transmission system operators in the Nordic countries want an efficient integrated Nordic electricity market. However, there are deficiencies such as the lack of locational price signals that involves non-optimal utilization of the Nordic power system and the international interconnections. During the last decade, there has been a lack of new investments in generation and transmission capacity at the same time as there has been a demand growth. The market design is of crucial importance when the electricity market is tested under stress conditions that include a scarcity of energy and capacity. It is also important to use market mechanisms during scarcity periods and the existing system should be used optimally before new investments are planned. This will benefit society in the long-run and will not result in over-investment. The experience from northeastern US electricity markets may tell us some lessons of how to deal with locational prices and transmission investments.

1.2 Objectives and scope of work

The goal of this thesis is to investigate risk management in the electricity market emphasizing the risks associated with transmission congestion. Many electricity markets have experienced under-investment in transmission and it is therefore important to create mechanisms for transmission expansion. As 99% of power generation in Norway is hydro-based and hydropower amounts for a substantial share of generation capacity in the Nordic market, it is therefore important to understand how to manage the risks of a hydropower producer.

The work on this thesis first started out with the objective of integrating hydropower scheduling and economic risk analysis. This is reflected in one of the papers included in the thesis. It describes the testing of the Prodrisk model that was developed as a part of the project. The model was implemented on Norsk Hydro ASA's power system and strategic contract portfolio, and was run in the weekly operation for half a year. However, the focus changed to risks associated with transmission congestion and how these could be managed by using financial derivatives. During the stay at Harvard, I started to study how it was possible to create incentives for merchant transmission investments.

To summarize, the research has been focused on the following issues:

- Evaluation of different market solutions for congestion management such as locational (nodal) and zonal pricing.
- Optimal power flow model and how to calculate locational prices.
- What trading strategies and tools for risk management associated with transmission congestion can or should be used?
- How well do the markets for transmission congestion derivatives (Contracts for Differences and financial transmission rights) function in terms of efficiency?
- How are the financial transmission right markets designed?
- What are the financial and economic consequences of buying financial transmission rights for market players such as generators, loads and traders?
- What are credit risks of the system operator when providing financial transmission rights?
- How can financial transmission rights be used to create incentives for transmission investments?

- Can risks be managed by using both operations scheduling and the utilization of financial contracts in real cases such as the power system of Norway's second largest hydropower producer?

1.3 Limitations

The study is limited to congestion management in the Nordic and US power markets and does not consider cross-border auctions that are used in continental Europe. The transmission risk management tools that are described are therefore only relevant for the locational and zonal pricing systems used in the US and Scandinavia respectively.

An efficient financial transmission rights model assumes no increasing returns to scale, no sunk costs, locational prices that fully reflect consumers' willingness to pay, network externalities internalized by locational prices, no uncertainty in congestion rents, no market power so that markets are always cleared by prices, complete futures markets, and an independent system operator (ISO) with no inter-temporal preferences regarding effective transmission capacity (Joskow and Tirole, 2002 and 2003).

Empirical data from markets for hedging instruments against locational price differences are still limited and immature so that analyses must be viewed in this light. There are also complications in the pricing of electricity derivates because of non-storability and transmission constraints.

When considering merchant electricity transmission expansion we limit ourselves to small-scale transmission investments that do not produce material changes in locational prices. In the context of the merchant transmission expansion model, the work does not consider the social welfare results as important as that electricity market players are hedged (with financial transmission rights) against possible externalities when there is a transmission expansion. Likewise, the financial transmission rights model is static and using it to analyze transmission investments will not consider the dynamic nature of these investments.

1.4 Disciplines and methods used in the thesis

To evaluate the issues raised in this thesis a multidisciplinary approach has been used. The issues related to financial transmission rights are solved by combining electrical engineering, economics, finance, and operations research as illustrated in Figure 1-1. A similar approach has been used when evaluating the Nordic Contracts for Differences. The integrated risk management model for hydropower scheduling and contract management uses methods from operations research and finance.

Specifically these concepts and methods have been used:

- Electrical engineering: optimal power flow model, congestion management, reliability
- Energy and regulatory economics: transmission resource allocation, property rights, optimal use of scarce resources, incentives for new investments, liberalization of electricity markets, market power
- Finance: pricing of electricity derivatives, value at risk, empirical analysis, hedging, optimal hedge, financial engineering

- Operations research: linear programming, nonlinear programming, bi-level programming, stochastic dynamic programming, stochastic dual dynamic programming, simulation

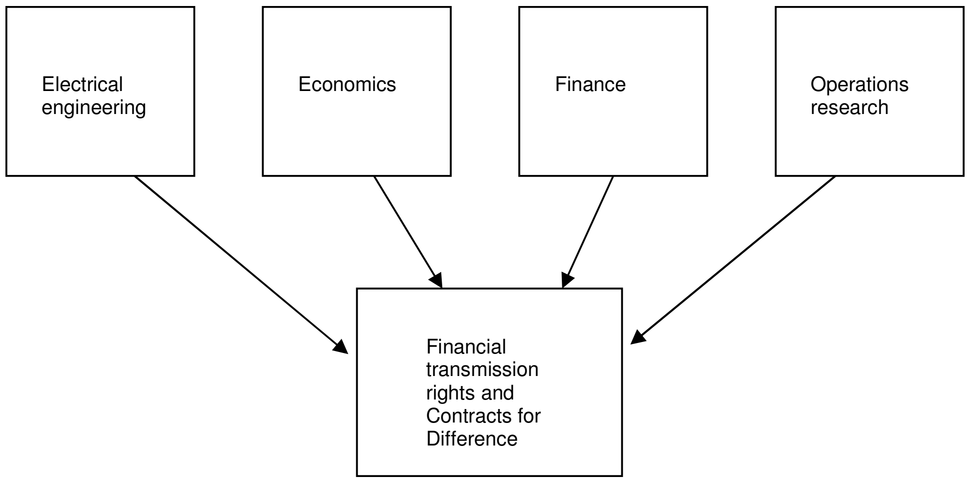

Figure 1-1. Disciplines used in the thesis to evaluate financial transmission rights and Nordic Contracts for Differences.

1.5 Summary of the thesis

Chapter 2 presents the theoretical background and review of the literature relevant for the thesis. This includes risk management, electricity market design, transmission pricing, transmission congestion derivatives, and transmission investments. It discusses the rationale for risk management in the electricity markets and the complications in pricing electricity. The objective for restructuring electricity markets is to obtain short-run and long-run efficiency through competition among generators and loads. In the short-run, there should be an optimal utilization of generation, distribution, and transmission. In the long-run, there should be incentives for the siting of generators and loads and optimal expansion of the transmission network. The major hurdle in the development of competitive markets arises from the need for a system operator who has a role in managing the complex interactions in the network and maintaining system reliability. The system operator role is discussed in the context of locational pricing markets and the Nordic market. Likewise, the congestion management procedures are described. Locational and zonal pricing are presented including mathematical transmission pricing models, and a comparison is made among them. To hedge locational price risk, transmission congestion hedging instruments may be used and we present the possible derivatives. Finally, we discuss transmission investments and one possible approach for attracting new investments in transmission in locational pricing markets – long-term financial transmission rights.

Chapter 3 presents a summary of the research papers and their findings.

Given that transmission congestion involves locational price risks, Chapter 4 gives an overview of how these risks can be managed by utilizing financial derivatives.

Risk management strategies are illustrated for trades between two locations when transmission congestion is present. Risk management in three different markets is exemplified: the general forward market, the bilateral market, and the Nordic market. Cash flow analysis describes the conditions under which hedging is profitable and demonstrates that players can protect themselves against futures price differences. Taking into account that a riskless hedge may be non-optimal if the objective is to minimize variance, the optimal hedge ratio for forward contracts is calculated.

Chapter 5 surveys the markets for FTRs around the world. It describes the features of the FTRs and the design of the different FTR markets. Here, we are especially interested in how FTRs can be acquired, their advantages and disadvantages, and their market performance.

Chapter 6 demonstrates how MATPOWER, a MATLAB package can be used for optimal power flow (OPF) simulations. An OPF simulation calculates the active/reactive power generated and purchased at each bus and the nodal prices. The nodal prices are of special interest because they reflect the marginal value of generation and load at each bus (node). These prices are also called locational prices and are found to be the optimal prices, maximizing social welfare and taking transmission constraints and losses into account. They can provide the right incentives to market players and maximize social welfare. When transmission congestion is present, this creates market inefficiency, since cheap distant generation may be replaced by more expensive generation. There is particular interest in OPF as utilized by a centralized dispatcher, and the features that are relevant for the Norwegian and Nordic markets. Three cases are optimized and the work analyzes the economic consequences of different network topologies and transmission congestion.

The purpose of Chapter 7 is to give an introduction to, and a pricing analysis of a CfDs, introduced on November 17, 2000 at Nord Pool. The CfD is a forward market product with reference to the difference between the future seasonal area price and System Price. By using available historical trading prices and spot prices for seven seasonal contracts and one yearly contract, it is possible to analyze the relationships between the contract prices and the value of the underlying asset. For the first seven seasonal contracts, it appears that the CfDs traded at Nord Pool are mostly over-priced relative to the underlying asset. Pricing theory for forward contracts explains this by the presence of a majority of risk-averse consumers who are willing to pay a risk premium for receiving the future price differential. Statistical analysis is utilized with regard to the contract prices and the underlying asset, and some interesting relationships are found. The analysis is preliminary because the CfD market is relatively new.

Chapter 8 proposes a merchant mechanism to expand electricity transmission based on long-term financial transmission rights (FTRs). Due to network loop flows, a change in network capacity might imply negative externalities on existing transmission property rights. The system operator thus needs a protocol for awarding incremental FTRs that maximize investors' preferences, and this preserves certain currently unallocated FTRs (or proxy awards) so as to maintain revenue adequacy. In this work, we define a proxy award as the best use of the current network along the same direction as the incremental awards. We then develop a bi-level programming model for the allocation of long-term FTRs according to this rule and apply it to different network topologies. We find that simultaneous feasibility for a transmission expansion project crucially depends on the investor-preference and the proxy-preference parameters. Likewise, for a given amount of pre-existing FTRs the larger the current capacity the greater the need to reserve some FTRs for possible negative externalities generated by the expansion changes.

Chapter 9 studies the risks faced by the providers of FTRs. The introduction of FTRs in different systems in the USA must be viewed in relationship to the organization of the market. Often, private players own the central grid, while an independent system operator operates the grid. The revenues from transmission congestion collected in the day-ahead and balancing markets should give the ISO sufficient revenues to cover the costs associated with providing FTRs. This can be ensured if the issued FTRs fulfil the simultaneous feasibility test described by Hogan. This test on a three-node network is studied under different assumptions to find the maximum volumes, which can be sold, including contingency constraints. Next, the feasibility test is analysed when taking into account the proceeds from the FTR auction, and demonstrate that a higher volume might be issued. We introduce uncertainty under different scenarios for locational prices and calculate the maximum provided volumes. As a tool for risk management, the provider of the FTRs can use the Value at Risk approach. Finally, the provision of FTRs by private parties is discussed.

Chapter 10 contributes to the understanding of how bus and area prices are affected by losses and congestion. Recent papers have described area pricing to include bus prices that are equal within in a price area or zone. According to present Norwegian practice, the bus prices within a price area differ by an amount that is due to losses. We use a full AC optimal power flow model to illustrate this. Moreover, we demonstrate that the combined effect of transmission congestion and losses may yield a substantial change in individual bus and area prices compared with a situation with no congestion or losses.

Chapter 11 describes a risk management tool for hydropower generators and its application to Norway's second-largest generation company and largest electricity consumer (Norsk Hydro ASA). The tool considers both operations scheduling and the utilization of financial contracts for risk management. Financial risks are accounted for by penalizing incomes below a reference income. The risk management problem is solved by a combination of stochastic dual dynamic programming and stochastic dynamic programming. Simulations demonstrate that lower income scenarios improve when risk aversion is introduced.

2 Literature review

This chapter aims to present a theoretical background and review of literature related to the papers in this thesis. It starts by describing risks that are faced by electricity market players and how these can be hedged by using financial derivatives. Because price risk is dominant, forecasting of spot prices is important and a brief overview of some models is presented. Next, we continue with the market design and system operator role that are the basic components in a competitive electricity market. Locational pricing and area pricing are discussed in the context of the northeastern United States (US) power markets and the Nordic market respectively. We also discuss financial transmission rights and Nordic Contracts for Differences as hedging instruments. An alternative locational hedging mechanism has been proposed by Rajaraman and Alvarado (1998). The basic idea is to use relatively few liquid futures markets, and construct a synthetic locational futures contract. The last part of the chapter discusses transmission expansion by means of long-term financial transmission rights and potential problems associated with this approach.

2.1 Risk management

In economic risk analysis, an economic value can be assigned to every possible outcome. In most cases, the economic value of an outcome is the net financial benefit associated with that particular outcome. In this context, risk might be defined as not getting an outcome within one particular range of values or greater than a threshold value. In finance, risk is the possibility of negative payoffs from derivatives, portfolios, and activities.

The term "risk management" is used to describe any kind of action that controls or changes the risk. This may be an increase or decrease in risk. Risk management can generally be defined as changing the risk to meet the decision maker's attitude toward risk. The objective of risk management is to ensure that contract positions, trades, insolvency, and operations do not expose the company to losses leading to financial default.

Risk management in the electricity market is a relatively new area that has been introduced after the restructuring of the electricity industry. Market players face new uncertainties such as price uncertainty. The price of electricity depends on supply and demand, and the price formation is complicated by the fact that electricity is non-storable and that supply must equal demand in real-time. Management of different types of risk as well as management of the total electricity portfolio[1] puts great requirements on expertise. Effective risk management will give the market player information about uncertainty in future net benefits. The market players would therefore achieve a more conscious attitude towards their exposure limits. Rational human behavior is identified to be risk-averse[2] (Arrow, 1971). A risk-averse agent seeks to reduce the uncertainties in net benefits. It will therefore be important to identify, assess, monitor, and control risks associated with activities within an electricity business company.

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[1] The electricity portfolio may include financial and physical contracts as well as electricity generation.

[2] Risk-averseness can be defined as preference for a certain payment of some value to a random payment with expected value equal to the same.

2.1.1 The risk exposure of an electricity company

The management of an electricity business company[3] must assess its risk exposures and establish rules for the contract portfolio that is consistent with the risk profile of the company. Furthermore, all risks should be understood, measured, and controlled. Appropriate risk measures and tools are therefore important (see Wangensteen, 2003). For an electricity company, all of the revenue and cost items would vary with the outcome of different factors. The important variable is the associated risk exposure of the sum of the items. Generally, an increased expected profitability brings higher risk, including the possibility of severe losses.

In finance, portfolio management has the objective to invest in a combination of assets that gives the highest expected return subject to the investor's risk profile. In the electricity market this means buying and selling the contracts that give the company the lowest purchasing price or highest selling price based on a chosen risk preference. One of the strategies to reduce the risk in finance is to diversify, but this option is limited in electricity markets (assuming a single agent). The company must evaluate its total portfolio of contracts and activities and calculate how a single contract contributes to the total risk. When entering into a single electricity contract, the relevant risk is the risk associated with the total portfolio.

Risk hedging can be done by modifying physical (hydropower[4]) generation plans, or by using financial contracts. An electricity company should hedge when the benefit probability distribution is changed such that the benefit is greater than the hedging costs, or when it is cheaper for the company than the owner to accomplish hedging. Hedging results in less volatile profit but requires skilled competence to analyze the electricity market. Forward prices may be used for the valuation of assets and marking-to-market of electricity portfolios.

2.1.2 Different types of risk

The strategic, market, and technical risks are the three main sources of risks for the players in the electricity market (Wangensteen, 2003).

Strategic risk is often called political risk and it is associated with changes in regulations and legislation. For example there may be changes in energy legislation, changes in concessions for power plants, new rules for export/import to foreign countries, changes in the domestic interest rate level, changes in the currency rate, and solvency problems in important customer groups.

Market risk is the dominating risk and is associated with changes in prices resulting from uncertainties in supply and demand of electrical energy. The supply of electricity is influenced by many conditions. In a hydropower-based system precipitation and inflow will be very important. In addition the temperature conditions are of importance since it affects the consumption and timing and speed of snow melting. Multi-year water reservoirs and import agreements during dry years contribute to decrease this uncertainty. Export of power to foreign countries affects the expectation about the future electricity price. If there is surplus of thermal energy

[3] Here the focus is on a generation or trading company, not a distribution company.

[4] This hedging strategy requires storage capacity over time and can typically be done by hydropower generators.

in the foreign countries this could give decreased prices in a hydropower-based system such as the Norwegian one. Conversely, if the thermal energy producers are heavily taxed this would give an increase in the electricity prices in the Norwegian system.

The electricity demand depends on many uncertain factors that affect the future electricity price. Temperature development in the long-run will affect the demand growth. In the short-run the uncertainty about the temperature has great influence, because it can change the assumptions for possible bidding in the spot market. The general activity in the economy will influence demand. If the level is high, the energy demand is high and with it the electricity demand. If a part of the electricity intensive industry is shut down, it will give a large surplus of electricity and therefore decrease the prices for a substantial time. The technological development will also have significance for the demand for electricity. Investments in energy efficiency equipment will typically give a reduced demand for electricity. New energy effective technology can change the consumers' demand pattern. Technological and financial developments can also change the demand and lead to competition between different energy carriers and energy forms.

The main components of market risk are price, basis (spot price minus futures price[5]), volume, counter-party, and liquidity risk. Price risk is associated with uncertainty in future price. Basis risk is due to the price difference between the spot price of the asset to be hedged and the futures price of the contract used (Hull, 2003). If the asset to be hedged and the asset underlying the futures contract are the same, the basis should be zero at the expiration of the futures contract. Volume risk is associated with uncertainty in the future volume. Counter-party risk is associated with the counter part being uncertain payer or supplier. Liquidity risk is the risk that a firm may not be able to, or cannot easily, unwind or offset a particular position at or near the previous market price, because of inadequate market depth.

In order to understand market risk we must model changes in price, understand the volatility for individual markets and the correlations between different markets. At a higher level, one can face the risk of poorly liquid markets that makes price discovery and hedging difficult.

Market risk is a major problem for participants that generate electricity subject to inter-temporal constraints. These are power plants where decisions taken at one time interval can restrict decisions taken after that. Storage hydro systems, plants with ramp-rate constraints, and plants with start-up costs are some examples of plants with inter-temporal constraints.

Technical risk is associated with outages of generation and transmission facilities. Distribution companies will be exposed to this risk. Technical risk does not affect the electricity market and the contract portfolio extensively because outages have short duration and occur infrequently.

[5] This is the usual definition. However, the alternative definition basis = futures price – spot price is sometimes used.

2.1.3 Derivatives

As most risk management is done by utilizing financial derivatives, we explain the basic types here. The two basic building blocks are forward and option contracts. Forward-based products include spot contracts (physical contracts), forwards, futures, and swaps. Option-based products include options, caps, floors, and collars, as well as hybrids, and options on futures, forwards, and swaps. One can also differentiate between standardized contracts, traded at exchanges, where clearing is often offered and OTC contracts, which are traded on a bilateral basis. There are four types of standardized contracts traded at power exchanges in Europe and elsewhere: spot contracts, futures, forwards, and options.

2.1.3.1 Spot contracts

The spot contract is normally an hourly contract, but can be even shorter, like the half-hourly spot contract traded at the Amsterdam Power Exchange. The spot contract has physical delivery and is the underlying reference price of most derivatives. The spot contract is not traded on a continuous basis, but through an auction conducted once a day.

The spot contract is a contract giving the buyer the obligation to receive a specified amount of MWs of electricity over the period, and the seller the obligation to deliver the same amount of power at a specific geographical location that might be anywhere in the transmission network or at a single hub.

2.1.3.2 Forward-based contracts

The electricity forwards and futures are normally traded on a continuous basis, which is also the case for forwards in most of the traditional financial markets. Their reference price is the spot price. A forward contract commits the buyer to purchase (and the seller to deliver) an asset at a specified time in the future at a pre-arranged price. They can be privately negotiated between two parties or traded at an exchange.[6] They often involve delivery of the underlying asset.

Futures are standardized forward contracts, traded on organized exchanges. The main difference between the futures and forwards is the daily marking to market and settlement of futures. Forwards are settled when the contracts reach their due dates.

A swap is a series of successively maturing forward contracts. Two parties agree to exchange a series of cash flows based on a liability or asset. Swaps are commonly negotiated on interest rates, currencies, commodities, and equities. Usually, a quantity of a commodity or a notional amount (a principal sum of money) is used to calculate the payment stream, but is not itself exchanged. Electricity swaps based on price indexes in different regions of the world may prove popular as restructuring evolves. In the Nordic market Contracts for Difference is an example of a swap.

There are several types of OTC forward-based contacts and their payoff structure may be complicated. An indexed contract may be used by the industry to hedge against uncertainty in the electricity price that makes up a substantial part of the cost and similarly the price of the output that makes up a substantial part of the revenue.

[6] This is the case at Nord Pool – the Nordic power exchange.

The contract specifies that the electricity price paid by the buyer is determined by an index that is referred to the output. Likewise, an electricity producer may be interested in a cross-market contract. This contract makes it possible to hedge against the simultaneous uncertainty in fuel and electricity prices that a thermal producer faces. The amount of fuel to hedge is however unknown, since it depends on the future dispatch and can therefore not be hedged with normal forwards or futures. Instead, there are products linking fuel price with electricity price to offset this spread risk. The cross market contracts can be swaps or options on this swap. The most common cross-market contract is a spark spread option. A long-term OTC contract with fixed quantity, but floating price is called a floating contract. The buyer pays the spot price in each period. The contract has the same cost structure as if the buyer is continuously buying electricity in the spot market.

2.1.3.3 Option-based contracts

Options are contracts that give the buyer the right, but not the obligation to purchase or sell the underlying asset at an agreed upon price in the future. Option buyers (long position) pay sellers (short position) a premium[7] for this right. Call options give buyers the right to *buy* the underlying asset from the seller at the prearranged strike or exercise price. Put options give buyers the right to *sell* the underlying asset at the exercise price. Some options are traded on organized exchanges, while others are traded over the counter. There are basically two types of traded options in power markets, namely European options with futures or forward contracts as the underlying and Asian options with spot contracts as the underlying.

Options that are “in-the-money” - the strike price is less, in the case of call options, or more, in the case of put options, than the market price of the underlying asset - can be exercised at a profit. Options that are “out-of-the-money” would be allowed to expire unexercised. European options can be exercised only at the specified exercise date, while American options may be exercised at any time up until the exercise date.

Caps and floors are simply series of consecutively maturing option contracts. A cap is a series of call options, and a floor is a series of put options. They are always negotiated OTC. Purchasing a call option or cap has a desirable payoff profile, but involves paying a premium. Risk managers sometimes fund the cost of acquiring a cap by simultaneously writing a floor. This combination of a long cap and a short floor is known as a collar.

A considerable component of risk in power trading is volume risk. Hence, many OTC contracts have flexible underlying volumes of electricity. These contracts are called swing options, because the buyer has the option to change its withdrawal from the contract over a certain period of time subject to an energy constraint. A typical example of a flexible contract is the load factor contract. It has a fixed amount of

[7] Option premiums are determined by supply and demand drives. Mathematical models are available for pricing options. Holding other variables constant, premiums will increase with volatility in the price of the underlying asset, and the length of time remaining to expiration. A call option premium also increases with an increase in the price of the underlying asset, but decreases with higher exercise prices. A put option premium will correlate negatively with the price of the underlying asset, and positively with exercise price.

energy and may be an annual contract with a specified utilization time. The flexibility inherited in the contract is found by dividing the utilization time by the total time.

Another type of flexible contract is an interruptible contract, where the buyer has the right to curtail supply at predefined number of occasions. It was introduced as a part of demand-side management programs and is an alternative to build more capital-intensive industry. The contracts are priced according to the frequency of the potential curtailments and how far in advance the notification must occur.

The swing option and the interruptible contract may be used to hedge volume risk, but they do not take into account the real source of uncertainty in supply and demand caused by the weather. This can be done by using weather derivatives that are structured as swaps, futures, and call and put options based on weather indexes. Commonly referenced weather indexes include, but are not limited to, heating degree day (HDD), cooling degree day (CDD), precipitation, and snowfall.

Real options are non-traded assets or liabilities for which the payoff profile replicates that of an options contract, may be embedded in traditional operations or contracts. For example, the decision to construct a new peaking power plant has the characteristics of a call option. The price of constructing the plant is equivalent to the option premium, and the price of operating the plant is equivalent to the strike price. Recognizing real options can help utilities understand tradeoffs between contracting, financial hedging, construction opportunities, and purchasing insurance.

2.1.4 The dynamics of the spot price

As in basic economic theory, the competitive price of electricity is determined by the intersection of demand and supply curves. To be able to price electricity derivatives and forecast prices we must have spot price models. The non-storability of electricity makes the utilization of models from finance more challenging.

The traditional models in finance are usually represented by stochastic differential equations. The most famous is the Black and Scholes model. In this model the stock price, S_t, in time period t follows a geometric Brownian motion (GBM):

$$dS_t = \alpha S_t dt + \sigma S_t dW_t \qquad (2.1)$$

where dW_t is an increment of a Wiener process. The Wiener-process[8] is a particular type of Markov stochastic process with a mean change of zero and a variance rate 1.0 per year. The deterministic part is represented by the first term where α is the drift in the spot price (expected return of rate). The second term $\sigma S_t dW_t$ is stochastic including the volatility σ. The equation is solved with Ito calculus (stochastic differential equation calculus) and has the solution:[9]

[8] It has been used in physics to describe the motion of a particle that is subject to a large number of small molecular shocks and is sometimes referred to as a Brownian motion.

[9] dW_t in a small time increment can be modeled as $\partial W_t = \varepsilon\sqrt{\partial t}$ where is a standard normally distributed stochastic variable. Equation (2.1) then has the solution $S_t = S_0 e^{(\alpha - \frac{\sigma^2}{2})t + \sigma\varepsilon\sqrt{t}}$.

$$S_t = S_0 e^{(\alpha - \frac{\sigma^2}{2})t + \sigma W_t} \tag{2.2}$$

The first term in Equation (2.1) is deterministic, while the last is stochastic. Empirical data show that the volatility of the spot price varies over time, and therefore a time dependent volatility may be needed.

One characteristic of electricity prices is mean reversion, meaning that they appear to move around some equilibrium level. A drift term must be included to model this. The term is negative if the spot price is higher than the mean reversion level μ and positive if the opposite is the case. The new model is then:[10]

$$dS_t = \beta(\mu_t - S_t)dt + \sigma S_t dW_t \tag{2.3}$$

The magnitude of mean reversion β determines how fast the price will revert to its mean level. The level of mean reversion will depend on the time to reflect that electricity prices tend to revert to different levels over the year (e.g. seasonal fluctuation). The electricity price also varies over the course of the day with high prices during peak load and low prices off-peak.

Other characteristics of electricity prices are jumps, which occur infrequently but may be large. The jumps come from substantial load fluctuations. Whenever demand is low the spot price is insensitive to changes in demand. However, when the demand is high, small changes in demand can have substantial impacts on the spot price, because demand is on the vertical part of the supply curve. The discontinuities in the supply curve translate into spikes in the spot price. To account for discontinuity in the price, common practice is to add a jump component to a process driven only by a Brownian motion. A possible model is:

$$dS_t = \beta(\mu_t - S_t)dt + \sigma S_t dW_t + \varphi S_t dq_t \tag{2.4}$$

where the last term represents the price jumps. The stochastic variable q_t accounts for the frequency of occurrence of jumps and φ is a stochastic variable describing the magnitude of each jump. The jump feature could be modeled with a Poisson process, and the stochastic variable φ could be time-dependent. Refer to Gibson and Schwartz (1990), Eydeland and Geman (2000), and Clewlow and Strickland (2000) for a further introduction to the field.

2.2 Electricity market design

Wilson (2002) identifies issues that complicate electricity market design. First, electricity is costly to store. Second, the transmission of electricity is carried out from generators to demand in meshed networks that can be affected by transmission constraints. Third, transmission property rights are difficult to define because of loop

[10] The most commonly used mean-reverting stochastic differential equation is the Ornstein-Uhlenbeck process.

flows. Fourth, the supply of generation through the transmission network must meet demand in real time, and reserves must be present to meet random demand shocks.

The objective of restructured markets has been to achieve overall short and long-run efficiency through competition. Competition is generally considered to work potentially in electricity generation and retail supply, because of cost-efficiencies. Competition is important because it gives the right incentives and prices. However, the transmission and distribution systems are natural monopolies that have increasing costs if two or more companies operated in parallel with the current one. A company is then able to produce with decreasing unit costs as the output increases. The transmission and distribution systems have externalities due to loop flows determined by Kirchoff's laws and other network effects. A competitive wholesale market is usually obtained by combining vertical separation of generation, transmission, coordination, and retail supply with an adequate regulatory framework and institutional design.

2.2.1 The electricity markets

There are four markets that characterize a complete electricity market: the forward transmission market, the spot energy market, the forward energy market (or market of bilateral contracts), and the forward reserves market (Wilson, 2002). According to Wilson's classification the spot market includes a real-time balancing market while the day-ahead market corresponds to the Nordic spot market definition. The complex interactions in these markets complicate a design of optimal incentives for the use of the transmission system and generation capacity in the short-run and transmission expansion and generation expansion in the long-run.

Congestion management requires coordination and this can be accomplished through the continuous spot market. In restructured electricity markets this function is taken care of by the system operator who manages the complex short-term interactions in the network and maintains system reliability. The system operator needs to be independent of existing electric utilities and other market players to avoid issues such as market power and strategic bids. Hogan (1999a) and Borenstein (2002) argue that the system operator must be allowed to offer economic dispatch (or pool service) based on marginal cost pricing. This is a centralized way of organizing the electricity market and assigns broad authority to the system operator. Market players may participate in the pool service, which effectively minimizes generation costs through a merit-order ranking of bids from generators. The pool service determines the market clearing price as the last dispatched generator. An alternative discriminatory auction mechanism is a pay-as-bid auction. However, it might lead to less competition and higher prices than the uniform-price auction (see Wolfram, 1999).

The task of the system operator is to manage real-time and day-ahead operations including longer-term horizons. By having available pre-arranged generation reserves, system stability can be achieved. The system operator obtains balance using the submitted offers and time differentiated categories of reserves.

The definition of a spot market is a market for immediate or very near delivery. According to most of the international literature this is an approximate real-time market. The spot market in the Nordic region is actually a day-ahead market, but still called a spot market. A pure spot market would not be possible in the electricity market, because the system operator needs to plan a feasible schedule. Likewise, not all power plants can change their output within minutes, and therefore the generation side needs notice in advance.

The Nordic market includes an electricity exchange or market operator, Nord Pool, which is responsible for receiving bids for purchase and offers for sales and match the bids so that the market is cleared. Market player participation is voluntary. One important activity of the exchange is the operation of the spot market which is the common market for the synchronous Nordic power system. Nord Pool is also responsible for the financial contract market.

In the pool-based markets a British contract for differences is a bilateral contact for hedging fully or partly against a single volatile spot price, and provides a hedge where parties mutually insure each other covering the difference between the contract price and the spot price (assuming a single spot price[11]). Bilateral contracts are of a physical or financial type. In mature electricity markets up to 80% of the transactions are long-term, 20% are day-ahead and less than 10% are spot (Wilson, 2002). In the Nord Pool market, the ratio between day-ahead[12] trades and long-term contracts was approximately 0.10 in 2002. Similarly the ratio between annual consumption and long-term contracts was approximately 0.03.

Another way of organizing the electricity market is to decentralize it (Wilson, 2002). In this case, the system operator manages transmission through transmission access and auctions of tradable transmission rights and counterflows to relieve transmission congestion. The system operator ensures that all schedules are simultaneously feasible and each market player self-schedules under discretion to meet contractual obligations. A decentralized system operator would manage transmission and reserves with little intrusion into energy markets. The system operator should permit a sequential optimization of the four electricity markets with voluntary participation of market players. The decentralized market has separate markets for energy, transmission rights and counterflows, and reserves and therefore sacrifices tight coordination (Wilson, 2002).

2.2.2 The design of the system operator

The system operator is a natural monopoly, but is also characterized by organizational and institutional issues such as governance, incentives, regulation, and economic objectives (Rosellon, 2003). The forward transmission market, the spot energy market, the forward energy market, and the forward reserves market present challenges to the system operator in achieving optimal incentives for expansion of transmission and electricity supply and reserves including an optimal use of generation in the spot electricity and forward markets.

There are three possible system operator structures according to Wilson (2002) to reach equilibrium for the four electricity markets. The first structure is a decentralized independent system operator (ISO), separated from the transmission owner. The decentralized ISO seeks to the least possible extent intervention in the four markets.

[11] To hedge against locational price differences an FTR may be used.
[12] In 2002, 32% of consumption was traded in the day-ahead market.

The second is a centralized ISO that manages and coordinates the four markets. The third is an integrated company (Transco[13]) that owns the transmission system and operates it. A combination of any of the three structures is also possible.

A decentralized ISO performs sequential optimization in the four markets with voluntary participating market players. Wilson (2002) argues that decentralization is better when incentives for cost minimization and efficient scheduling of each player's pool are more important than coordination in electricity markets. On the contrary, Hogan (1995) argues that any decentralized market can be centralized through adequate definition of access and pricing.

The centralized ISO performs a simultaneous minimization of the reliability, generation, transmission, and reserves costs in the four markets. It is also in control of the real-time dispatch and reserve options are mandatory. The ISO can call upon the generators to schedule up or down generation to reduce power flows.

The Transco structure is similar to a centralized ISO but with the central dispatcher also being the owner of the transmission system.

Variants of the decentralized ISO model are found in Australia, Scandinavia, California 1998-2000, Texas, and the United Kingdom's new system of 2001. The centralized ISO model has been applied in the United Kingdom 1989-2001 and is in use in New England, New York, and Pennsylvania – New Jersey – Maryland (PJM). As a part of the standard market design (SMD) in 2002, The Federal Energy Regulatory Commission (FERC, 2002) required transmission companies to join a regional transmission organization (RTO) in order to obtain a vertical separation of generation and transmission. The Transco structure is applied in the United Kingdom and Spain.

In the Nordic region, the system operator role is assigned to the transmission system operators (TSOs). They are responsible for keeping their control area electrically stable (frequency of 50 Hz) and for security of supply within their region. The TSOs are both owners and system operators of their respective grids.[14] The Nordic market design includes Nord Pool and the TSOs. The exchange and system operator roles are related in that inter-regional congestion in the day-ahead market is handled by the exchange, while intra-regional real-time congestion[15] is handled by the TSOs. Hence the Nordic market design integrates both the TSOs and the exchange in system operation.

2.3 Transmission pricing

The electricity transmission network has an important function in facilitating trade of electricity between geographically dispersed markets. Because many generators are interconnected via the transmission network, together they can provide improved reliability and lower overall generation costs (Hsu, 1997). The complexity of analyzing electricity networks stems from Kirchoff's laws which govern the power

[13] An independent company that combines ownership of the grid and responsibility for system operations in managing the use of the grid. It may be a for-profit or not-for-profit entity.
[14] In Norway 80% of the grid is owned by the main system operator Statnett.
[15] Nord Pool also facilitates a real-time market for Sweden and Finland.

flows. The network topology and characteristics together with the joint interaction of transmission congestion, losses, and energy prices from injections and withdrawals of electricity contribute to the formation of electricity prices at different locations. The correct pricing of electricity transmission is crucial in providing signals to the market players for efficient short-run use and long-run capital investments. In the short-run, demand functions are given and the objective is to optimize the use of generation, distribution, and transmission capacity. In the long-run, the objective is to create incentives for the siting of generation and transmission expansion.

In electricity transmission systems there are mainly three short-term cost components that must be considered; the congestion cost, the cost of losses, and the cost of ancillary services such as reactive power (Bjørndal, 2000). Congestion cost is the cost resulting from scarcity of transmission capacity. Transmission congestion affects the economics of the network in that cheaper generation is replaced by more expensive generation in order to reduce power flows. In the deficit and surplus areas, the optimal price of electricity is equal to the local marginal cost of generation, or to the local willingness to pay. The price of transmission usage between any two locations is defined as the difference in locational prices between those two locations. Marginal losses may give considerable price differences for some of the locations and small deviations from the uncongested case can make even larger effects. These differences could have a significant effect in the siting of generators and loads. Generators provide ancillary services[16] such as regulation[17] and frequency control, spinning reserves, supplemental reserves, backup reserves, voltage control, and black start. It appears that, in many regions, the first four of these services can eventually be provided by many suppliers or customers through competitive markets. The latter two services, by contrast, have locational characteristics that limit potential competition; so it is likely that they will continue to be provided through non-competitive institutional mandates.

2.3.1 Transmission pricing methods

There are different methods for pricing transmission: locational (nodal) pricing, zonal pricing, uniform pricing, and Chao-Peck pricing. Locational pricing (Hogan, 1992) maximizes social welfare taking into account transmission constraints and losses, and is performed by a centralized ISO. In this case, the price of electricity at each location equals the marginal cost of providing electricity at that location. An alternative solution is zonal[18] pricing where several buses are grouped into zones, and the price differentials between the zones are calculated from more or less simplified models. In this case social welfare is reduced and there is lack of price signals for the siting of generators and loads. Hogan (1999b) argues that locational prices are based on the principles of economic dispatch and "are self policing and self auditing," while zonal pricing implies deviations from optimal and reliable dispatch. Green (1998) shows that by applying uniform pricing, inferring that location means nothing, welfare is reduced even if transmission constraints are managed through efficient redispatch. This also gives incorrect incentives in the long-run. An alternative to these approaches

[16] The Norwegian hydro-based power system includes the following ancillary services: primary reserves (frequency control), secondary reserves (manually controlled), reactive power, frequency activated load shedding and generation shedding.
[17] Regulation may be provided by load as reduced demand.
[18] In the US, zonal pricing is a term that is commonly used. In the Nordic system area pricing is used for essentially the same concept.

is to use Chao-Peck pricing (Chao and Peck, 1996) which entails explicit congestion pricing. The use of scarce transmission resources is priced, in contrast to locational pricing which prices the use of energy (Stoft, 1998).

In a locational pricing system, the congestion fee for transferring electricity between two locations is calculated as the difference in locational prices times the quantity transferred. In a zonal pricing system, the fee is calculated as the difference between the zonal prices times the quantity transferred (within Norway it is defined as the difference between the area price and the System price). The ISO (in a locational pricing system) or the TSO (in an area pricing system)[19] receives a surplus during transmission congestion periods and when losses are present, because net payments from loads exceed net payments to generators.

In the long-run, the most important objective of transmission pricing is to provide the right incentives for the siting of new generation and loads. Additionally transmission network owners should expand the network optimally given the right incentives and compensation. Assuming constant or decreasing returns to scale in the transmission system, the long-run efficiency could consist of a sequence of optimal short-run pricing decisions as pointed out by Hogan (1992). However, the transmission system has typically a nonlinear or lumpy cost function. Therefore, the long-run efficiency may not be attainable in a decentralized market-based system, but obtained through different regulatory mechanisms with central investment decisions (Bjørndal, 2000).

2.3.2 Economic dispatch and optimal prices

An efficient pricing scheme in the scheduled electricity market has been the economic dispatch, which can be formalized as:

Max producer and consumer surplus
s.t. power flow equations (2.5)
transmission capacity constraints
reliability and security constraints
active and reactive power generation limits

The objective function consists of the sum of the consumer and producer surpluses which in turn equals social welfare. The power flow equations describe how electricity distributes from net injections in the network. To prevent over-load of a transmission line, transmission capacity constraints are added. There are two types: thermal constraints and voltage constraints. The thermal constraints deal with power flows that heat up the transmission line. Voltage constraints deal with reactive power flows. The reliability and security constraints may include restrictions on voltage or generator and transmission line outages (also called contingency constraints). Power balance must be maintained to guarantee continuous supply, even after a disturbance in the system such as the failure of a generator or the outage of a transmission line. The contingency constraints concern the ability to prevent cascading outages as a result of disturbances in the power system.

[19] Note that this depends on how the TSO is regulated. For example in Norway the TSO has a revenue cap on its revenue.

A solution of this nonlinear program results in a set of first order conditions that yields the generated and consumed electricity at each bus. The Lagrange multipliers associated with the power flow equations are the locational or nodal prices. They reflect the marginal generation cost and marginal benefit to load at each bus. They also give the marginal valuation of the production costs (such as fuel costs, operation costs, and water values) and the marginal value of losses and congestion in the network by marginal generation/load at each bus. Ideally, locational prices should be calculated both for active and reactive power (Hogan, 1992). However, there are no markets for reactive power so it is provided as an ancillary service.

The power flow equations are generally highly nonlinear and the maximization problem is non-convex. Under normal operation of a power system, it is possible to consider only active (real) power and assume no losses. Likewise, voltage magnitudes are kept close to rated levels and phase angles are small such that it is possible to approximate the real power flow equations by convex functions. If the objective is well-behaving the above problem is convex (at least locally) which is a necessary condition for the existence of an efficient market mechanism to replicate social optimum as discussed by Chao and Peck (1996). The locational pricing generalization is mathematically complex to do in practice but it is implemented in the northeastern US power markets.

The power flow in a meshed grid distributes in such a way that every change in generation, load or transmission capacity affects the flow in the entire network. This phenomenon is known as loop flows. It may mean that power flows from a high price bus to a low price bus as illustrated in Figure 2-1. Loop flows imply that certain transmission investments might have negative externalities[20] on the capacity of other (perhaps distant) transmission links (see Bushnell and Stoft, 1997). Moreover, the addition of new transmission capacity can sometimes paradoxically decrease the total capacity of the network (Hogan, 2002a).

One active transmission capacity constraint may affect the locational prices at all other buses. Likewise, a change in generation or load will affect the marginal losses in the entire network. The electricity price therefore changes from location to location because of losses and transmission constraints.

The analysis of locational pricing makes several simplifications (Hsu, 1997). Generation is assumed to be dispatched optimally such that the price equals marginal cost which in turn exceeds the average cost. Then the operating revenues will be greater than the total costs. The economic dispatch should be distinguished from unit commitment which looks forward to expected demand. The unit commitment problem considers plant characteristics such as startup costs, ramp rates, and minimum downtime in addition to the variable generation costs. Conversely, the economic dispatch only considers the next time interval (for example an hour) with available generation. The multi-period coupling in unit commitment greatly complicates the scheduling problem. Additionally, demand and generation cost functions are assumed

[20] Network externalities, which can be good or bad, describe the benefit or cost imposed on other market players when one market player changes supply or demand or the transmission capacity of a line.

to be constant in the short-run. However, demand functions may be uncertain even in the short-run.

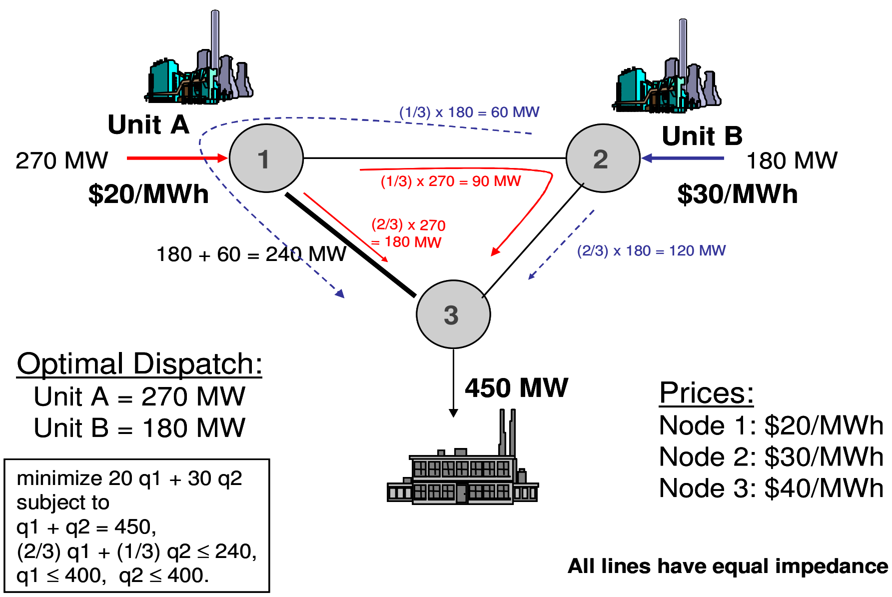

Figure 2-1. Locational price example with loop flow (Singh, 2003).

2.3.3 Nordic transmission pricing

The Nordic region has area pricing where buses are grouped into areas that are bounded by potential transmission constraints. Each area has a spot price and the unconstrained spot price for the Nordic power market is named the System Price. Norway utilizes marginal loss charges for 168 buses.

Bottlenecks may have temporary or structural causes. Temporary bottlenecks occur relatively rarely and may be the result of maintenance work, technical faults or particular market conditions. Structural bottlenecks are a result of the level of expansion of the grid and the localization of generation and consumption within the grid. Structural bottlenecks tend to occur over longer periods of time or at regular intervals. It is important to differentiate between temporary and structural bottlenecks when selecting methods of managing congestion even though it is often difficult to distinguish between the two types of bottlenecks.

In the literature, market splitting is also used for the term area pricing. Market splitting entails the partition of nodes into different pre-defined price areas on either side of the transmission constraint. Market splitting is characterized as an implicit auction where transmission capacity is allocated simultaneously with electricity trade at Nord Pool. It is a simple, inexpensive, and efficient method for managing structural bottlenecks. Market splitting is also utilized on the cable interconnections of Skagerak, KontiSkan and Øresund managed by Nord Pool.

On the contrary, in continental Europe the allocation of energy and transmission capacity occur in two steps. The right to utilize transmission capacity on a link in a certain direction and period is auctioned to market players in explicit auctions while the energy is traded in the spot markets. Auctions between Jutland and Germany are conducted by Eltra and E.ON Netz (transmission system operators in western Denmark and Germany respectively) annually, monthly, and daily. Capacity purchased in the annual and monthly auctions may be resold before contract delivery. Unused capacity is subject to the “use-it-or-lose-it” principle and released in daily auctions. It may happen that the electricity flows in the direction opposite what was anticipated.

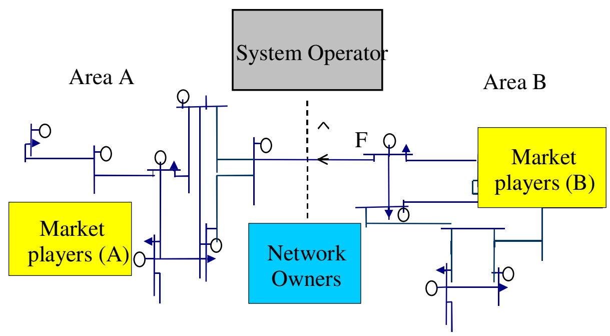

Figure 2-2. Players involved in congestion management (Grande and Wangensteen, 2000).

The various players involved in congestion management are illustrated in Figure 2-2 (Grande and Wangensteen, 2000). In the Nordic model the electricity exchange, the TSOs and market players work together. For efficient operation and a well-functioning market these must have clearly defined responsibilities. The network owner’s principal responsibility is to build, operate, and maintain the network. The system operator[21] manages non-predictable imbalances and unexpected events during real-time that cannot be relieved by trade in the market. The system operator is responsible for definitions of transmission capacities and optimization of physical operation. Intra-area congestion is managed through counter trades by the system operator. The system operator function is assigned to the network owner. In the Nordic system the market operator (Nord Pool) is responsible for managing inter-area congestion through area pricing in the day-ahead market. The market players are entities that operate in the wholesale and/or retail market. The market players bid into predefined spot areas which become price areas when transmission congestion is present. In a counter trade arrangement they may be called upon by the system operator to provide electricity or curtail load. The regulator determines guidelines and bylaws for the regulation of monopolies within the power business. Generally, this will cover grid issues such as cost recovery through network tariffs and the settlement of disputes concerning network tariffs (Nord Pool, 2002b).

The Nordic market consists of 5 control areas: Norway, Sweden, Finland, Denmark-East, and Denmark-West. Area pricing is used for congestion management

[21] In Norway Statnett is both transmission system operator (TSO) and network owner (approx. 80 % of the main grid).

within Norway and among the control areas. Norway is divided into several areas while Sweden, Finland, Denmark-East, and Denmark-West are separate areas. Counter trades are used for transmission constraints within each area and to ensure real-time balance between supply and demand.

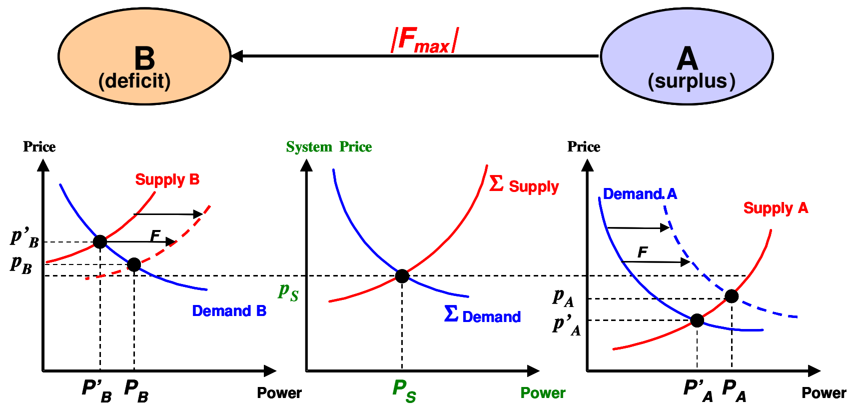

Figure 2-3. Area price calculation (Grande and Wangensteen, 2000).

In area pricing the market is first cleared ignoring all transmission constraints. This calculation results in the System Price p_S and the amount of power traded as illustrated in Figure 2-3. If the amount of power exchanged F is greater than the transmission capacity, the buses in the network are partitioned into areas on either side of the bottleneck. In the case of two defined areas, the surplus area is the low price area while the deficit area is the high price area. The exchange of power between the areas is fixed to meet the maximum transmission capacity. Two new area spot prices are determined based on the initial bids in the spot market in each area and maximum transmission capacity. Congestion between two areas leads to a higher price in the deficit area, reducing net demand, and a lower price in the surplus area, increasing net demand. The surplus[22] to the network owners equals the difference in area prices times the amount of power exchanged between the areas and is named the congestion fee.[23] Various area allocations have different impacts on the electricity market players' revenues and costs and may result in conflicts of interest.

For counter trades the first stage is the same as for area pricing. If the amount of exchanged power is greater than the maximum transmission capacity, the system operators check where generation or load can be curtailed or increased to relieve congestion. The generators that are scheduled up (or loads that are reduced) or down (or loads that are increased) are compensated in a separate market, the regulation power market, where generators and loads submit adjustment bids. The system operator selects the less expensive bids for increases and decreases and pays the participants the equilibrium price in the regulation power market. Counter trade

[22] Network owners have a regulatory cap on revenue in Norway such that the surplus will *not* represent a real profit.

[23] In Norway the price difference between the area price and System Price is called "Kapasitetsavgift" (capacity fee).

involves an expense for the system operator because it has to buy and resell power according to the adjustment bids. It therefore has no incentives for creating transmission congestion. During counter trade, there will be only one spot price in the market. However, regulating objects used for rescheduling will receive a different price.

While market splitting is a part of the spot market settlement, the counter trade arrangement is applied in the operational phase. The different timing of the congestion management procedures with these two arrangements is shown in Figure 2-4. The area prices are calculated based on aggregated supply and demand bids in each area. Prices are therefore settled without physical references to trades within each area. The spot market settlement is done 12 hours before the first hour of operation (12 am). In the preoperational phase the exact production plans and the bids on the regulating power market are given to the system operator. This information is the basis for the counter trade. The counter trade is carried out in the hour of operation.

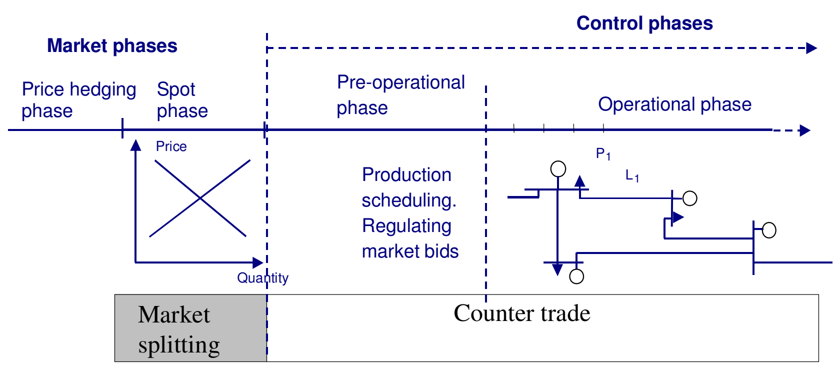

Figure 2-4**.** Congestion management in the time scale (Grande and Wangensteen, 2000).

2.3.4 Chao-Peck prices

Unlike locational pricing which prices energy, Chao-Peck prices price the use of scarce transmission resources. The Chao-Peck prices are based on the definition of transmission capacity rights, which entitle the owner the right to inject one unit of electricity through a specific line in a specific direction (Bjørndal, 2000). The issued set of transmission capacity rights is consistent with power system constraints and is tradable. A trading rule is established to control the exchange of rights by specifying the rights that traders must acquire so as to accomplish an electricity transaction. Power flows are distributed according to the power transfer distribution factors (PTDFs). The PTDF H_{ij}^{mn} is the fraction of a transaction from bus m to bus n that flows over a transmission line connecting bus i and bus j. If the price of transmission capacity on line ij is η_{ij} (assuming a lossless network), then the transmission cost of a trade of unit of electricity between buses m and n is calculated as $\sum_i \sum_j \eta_{ij} H_{ij}^{mn}$, where the summation is over all buses.

The Chao-Peck prices (CP_{ij}) associated with a congested transmission line between buses i and j can be calculated from the locational prices as $CP_{ij} = (P_j - P_i) / F_{ij}$ where P is the locational price at the respective buses and F_{ij} is the flow factor (similar to the PTDF). The flow factor is the ratio of power that would flow over the line *ij* if 1 MW was injected at bus *i* and withdrawn at bus *j*. Likewise, the Chao-Peck prices can be calculated from shadow prices associated with the transmission capacity constraints in the economic dispatch as well as the shadow prices associated with the power flow equations. The Chao-Peck prices are therefore consistent with the locational prices.

There are three properties of Chao-Peck prices that are different from locational prices:

- Uncongested transmission lines receive a price of zero.
- Congested lines always have a positive price in the flow direction.
- The number of positive prices equals the number of congested lines. This number is usually far less than the number of buses in the power system.

Chao-Peck pricing is based on a decentralized market design without a central agency that collects information to solve the economic dispatch. Chao and Peck (1996) suggest that congestion prices could result from agents that are maximizing congestion rents simultaneously as generators are allowed to break even. However, a trade between two locations may affect all lines in the network and therefore the agents may have to purchase several rights. As transmission line owners may have substantial market power, Stoft (1998) offers some solutions to these problems. First, there could be restrictions on the ownership of a line. Second, the line owners could be required to sell the entire capacity of lines and therefore supposedly drive the price of unused rights to zero. Finally, Stoft suggests introducing a centralized initial auction and a successive bid-ask market for the continuous trading of transmission capacity rights until real-time to determine prices.

2.3.5 Transmission pricing and market power

There are a number of reasons why locational prices do not reflect marginal costs, such as market power, regulatory interventions, the absence of a complete representation of consumer demand in the wholesale market, and discretionary behavior by system operators under extreme conditions when the network is constrained (Joskow and Tirole, 2003). Here we can discuss the issue of market power. The definition of market power usually entails that a generator in a monopoly position is withdrawing output in order to drive the price up.

To illustrate the market power concept an example is used from Wangensteen (2003), Figure 2-5, where there is a generator located in a load pocket with limited demand connected through a transmission line of capacity *K* to a large market with price *Ps* which is unaffected by the generation in the load pocket. We assume locational pricing and observe that in an import-constrained situation the generator can withdraw output and receive a higher price than when the transmission constraint does not bind. A hydropower producer in a two-period setting that wants to exercise market power could produce more than the competitive case in the first period so as to induce the import transmission constraint in the second period. Then it will produce less than the competitive case and receive a higher price (see Figure 2-5). Its total profit for the two periods will then be higher than the competitive case and market power is exercised.

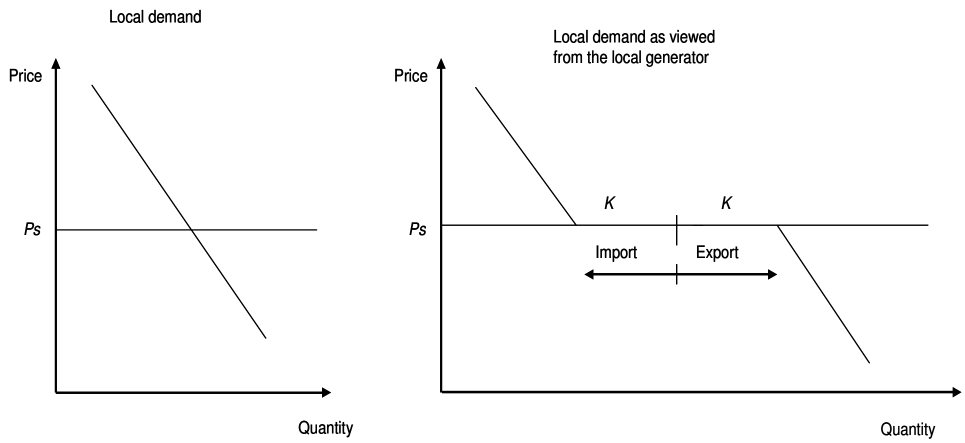

Figure 2-5. Impact of a transmission constraint on local demand.

Borenstein, Bushnell, and Stoft (1998) demonstrate that it can be profitable for generators to withdraw output so as to constrain a transmission line that would have been unconstrained under perfect competition. Oren (1997) presents an example of a three-node network where two strategic generators are located on each side of a transmission constraint. The problem is solved by using a Cournot game by Stoft (1998) and its corresponding interpretation is given by Joskow and Tirole (2000). They find that produced quantities from generators at two different buses can be turned into "local complements" and create incentives to withdraw output at one bus in order to constrain the output of the other generator resulting in higher prices. Hogan (1997) demonstrates that strategic generators owning generation at buses *A* and *B* in a three-node network might increase output at bus *A* relative to the competitive benchmark if loop flows reduce the total net demand at bus 2 and increase the price. Neuhoff (2003) considers the effect of market power in separated and integrated markets for transmission capacity and spot electricity in three cases: the unconstrained case, the partially constrained case, and the fully constrained case. Neuhoff concludes that market power is mitigated, if the transmission and electricity markets are integrated in a locational pricing system or a market-splitting system. Neuhoff's empirical findings support Hogan (1997) in that separate electricity and transmission markets are inefficient under uncertainty. Harvey and Hogan (2000) compare market power under nodal and zonal pricing and find that market power is always weakly lower under locational pricing than zonal pricing (two buses grouped into a single zone).

According to Harvey and Hogan (2000) there are at least four reasons why locational pricing is often superior to zonal pricing in competitive terms when the potential for the exercise of locational market power exists. First, zonal pricing can create market power in the hypothetical zonal dispatch that does not exist in neither locational nor inter-zonal pricing. Second, market power can arise in zonal redispatch that does not exist in the actual power market under either nodal or inter-zonal pricing. Third, by reducing demand response in the constrained region, zonal pricing can make the exercise of market power profitable that would be unprofitable in both locational and inter-zonal pricing. Finally, zonal pricing including the redispatch mechanism can reduce supply elasticity across unconstrained interfaces making profitable the exercise of market power that would be unprofitable under locational pricing.

Johnsen (2001) analyzes market power due to transmission constraints in the Norwegian electricity market. He uses a two-period model to demonstrate that market power leads to less storage in the first period than in the competitive case. A monopolist will find it profitable to produce more than the competitive output in the first period so as to induce import transmission constraints in the second period, raising the electricity price. Empirical results from the western part of Norway with a high concentration on the supply side support the model. Additionally, in a hydropower-based system transmission investments have two effects. First, increased export capacity in the first period leads to lower reservoir levels. Second, larger import capacity in the second period reduces the possibilities for the exercise of market power.

2.3.6 Mathematical transmission pricing models

Several models can be used to calculate transmission prices (Wangensteen, 2003; Hogan, 2002b)

- DC-models: The transmission network is described as a DC network.[24] These models can have both losses and congestion.
- DC-equivalent models: The transmission network is described as an AC network with a DC-like approximation.[25] The models ignore losses, but can have congestion.
- AC approximation model: The transmission network is described as an AC network and the losses are approximated by a term proportional to the square of the power flows.
- Full AC-model. The transmission network is correctly described as an AC network.

The DC-models are relevant in case of modeling of transmission prices in a DC network. The DC-equivalent models are extensively used in transmission pricing of networks that ignore losses. The AC approximation model was first described by Transpower New Zealand (Hogan, 2002b). It includes one-half of losses for every line flowing in or out of the bus. The problem is then nonlinear, but captures some of the interaction between the losses and congestion. Likewise, additional power flows are needed to compensate for losses. The full AC model is used when the joint interaction of losses and transmission congestion is important.

In the original Schweppe formulation (Schweppe et al., 1988) the locational prices are calculated taking into account losses by assuming that losses are balanced at the

[24] A DC network has only resistance, while an AC network has both resistance and reactance.
[25] It is assumed that there is sufficient reactive power net load at each bus to fix per unit voltages equal to 1 and that the voltage angle differences across lines are small. The DC-load equivalent flow refers to the real power part of the nonlinear AC load flow model. There is a weak link between the reactive power and real power halves of the complete problem.

swing (reference) bus.[26] The model takes the DC load flows without losses and then computes the total losses and prices them in effect at the swing bus. However, losses do not create any line flows. The locational prices depend on the swing bus price,[27] losses, and congestion.

In the optimal power flow (OPF) and the economic dispatch models, the choice of the swing bus is independent of the locational prices and the dispatch.[28] We use the full AC model and the DC-equivalent model in this thesis.

In OPF calculations it is convenient to separate the variables in three categories controls, states, and constraints (Weber, 1997). The control variables represent quantities that can be arbitrarily manipulated, within their limits to minimize costs. These may include active and reactive generator outputs, transformer tap ratios, and transformer phase shift angles. The states correspond to quantities that are set as a result of the controls, but must be monitored. Examples are system voltages and angles that are of interest at the solution. The constraint variables are the Lagrange multipliers of the constraints in the OPF. These give marginal values of changes associated with the constraints.

2.3.6.1 An alternative optimal power flow model

An alternative OPF model can be formulated as (Wangensteen, 2003):

$$\begin{aligned}
&\text{Max } B(\boldsymbol{P_L}) - C(\boldsymbol{P_G}) \\
&\text{s.t.} \\
&\boldsymbol{g}(\boldsymbol{x}, \boldsymbol{P_L}, \boldsymbol{P_G}) = 0 \\
&\boldsymbol{h}(\boldsymbol{x}) \leq 0
\end{aligned} \tag{2.6}$$

where B is the load benefit and C is the generator costs. $\boldsymbol{P_L}$ and $\boldsymbol{P_G}$ represent active load and generation vectors at each bus and $\boldsymbol{x}$ is a state vector representing voltage. $\boldsymbol{g}(\boldsymbol{x}, \boldsymbol{P_L}, \boldsymbol{P_G})$ denotes the power flow equations and $\boldsymbol{h}(\boldsymbol{x})$ denotes the transmission capacity constraints. Constraints on generation capacity are inactive and therefore omitted. The model is applied on a DC network and the current from bus i to bus j is described as $I_{ij} = \frac{(V_i - V_j)}{R_{ij}}$ where V is the voltage and R the resistance. Similarly, the net power injected at bus i is calculated as $g_k(x, P_{Li}, P_{Gi}) = P_{Gi} - P_{Li} = \sum_j V_i I_{ij} = \sum_j \frac{V_i(V_i - V_j)}{R_{ij}}$ where the summation is over the buses connected to bus i. The transmission capacity constraints are expressed in terms of the voltages and the resistances as $h_k(x) = \frac{V_j(V_i - V_j)}{R_{ij}} - C_{ij\max} \leq 0$ where $C_{ij\max}$ is the maximum

[26] Personal communication with Professor William Hogan.

[27] In the case that the swing bus has limited generation (i.e., a finite price elasticity), then the choice of the swing bus could affect the dispatch and the prices (Hogan, 2002b).

[28] However, the choice of the reference bus for pricing, which need not be the same as the swing bus, does affect the decomposition of the prices (Hogan, 2002b).

transmission capacity over line *ij*. Constraints on voltage could also be included and would have impact on reactive power. Here we focus on active power.

The associated Lagrangian is:

$$L(\boldsymbol{P}_L, \boldsymbol{P}_G, \lambda, \boldsymbol{\mu}) = B(\boldsymbol{P}_L) - C(\boldsymbol{P}_G) - \boldsymbol{\lambda}^T \boldsymbol{g}(\boldsymbol{x}, \boldsymbol{P}_L, \boldsymbol{P}_G) - \boldsymbol{\mu}^T \boldsymbol{h}(\boldsymbol{x}) \quad (2.7)$$

where $\boldsymbol{\lambda}$ and $\boldsymbol{\mu}$ are the Lagrange multipliers associated with the power flow equations and transmission constraints respectively. The Kuhn-Tucker conditions yield:

$$\begin{aligned}
&\nabla_{P_L} B(\boldsymbol{P}_L) - (\nabla_{P_L} \boldsymbol{g}(\boldsymbol{x}, \boldsymbol{P}_L, \boldsymbol{P}_G))^T \boldsymbol{\lambda} = 0 \\
&-\nabla_{P_G} C(\boldsymbol{P}_G) - (\nabla_{P_G} \boldsymbol{g}(\boldsymbol{x}, \boldsymbol{P}_L, \boldsymbol{P}_G))^T \boldsymbol{\lambda} = 0 \\
&\nabla_x \boldsymbol{g}(\boldsymbol{x}, \boldsymbol{P}_L, \boldsymbol{P}_G)^T \boldsymbol{\lambda} + \nabla_x \boldsymbol{h}(\boldsymbol{x})^T \boldsymbol{\mu} = 0 \\
&\boldsymbol{g}(\boldsymbol{x}, \boldsymbol{P}_L, \boldsymbol{P}_G) = 0 \\
&\boldsymbol{h}(\boldsymbol{x}) \le 0, \quad \boldsymbol{\mu}^T \boldsymbol{h}(\boldsymbol{x}) = 0, \quad \boldsymbol{\mu} \ge \boldsymbol{0}
\end{aligned} \quad (2.8)$$

Utilizing that $\partial g_i / \partial P_{Gi} = 1$ and $\partial g_i / \partial P_{Li} = -1$ we find the optimal locational prices as $\boldsymbol{\lambda} = \nabla_{P_L} B(\boldsymbol{P}_L^*) = \nabla_{P_G} C(\boldsymbol{P}_G^*)$. The locational prices equal the marginal benefit to load[29] which in turn equals marginal cost at each bus. Likewise the locational prices will be affected by the transmission capacity multiplier $\boldsymbol{\mu}$ through the relationships in Equation (2.8).

2.3.6.2 Optimal power flow model and locational prices

In the "classical" optimal power flow model, the objective is to minimize generator costs[30] of meeting load for a power system while maintaining system security. The objective in the OPF can be obtained from the Wangensteen model by assuming that load is constant, which results in a cost minimization. The costs of the system may depend on the situation, but generally, they are attributed to the generation costs. From the OPF viewpoint, the maintenance of the system requires keeping each device in the power system within its desired operation range in a steady-state situation. This will include active and reactive power limits, line flow limits, voltage limits, and contingency constraints. Topics such as transient stability, dynamic stability, and steady-state contingency analysis are not considered (Wood and Wollenberg, 1996).

We use the formulation of Finney et al. (1997) where we assume no binding generation capacity constraints:

$$\begin{aligned}
&\min_{P_G, Q_G, V, \theta} C(\boldsymbol{P}_G) \\
&\text{s.t.} \\
&\boldsymbol{F}(\boldsymbol{P}_G, \boldsymbol{Q}_G, V, \theta) = 0 \quad (\lambda) \quad \text{(power balance)} \\
&\boldsymbol{G}(\boldsymbol{P}_G, \boldsymbol{Q}_G, V, \theta) \le 0 \quad (\boldsymbol{\mu}) \quad \text{(line and voltage constraints)}
\end{aligned} \quad (2.9)$$

[29] Marginal willingness to pay.
[30] The objective function can take different forms such as minimum losses.

where C is the cost function, $\boldsymbol{P}_G$ and $\boldsymbol{Q}_G$ denote the vectors of real and reactive generation, and V and θ are bus voltage magnitudes and angles. Real and reactive loads are assumed to be inelastic. The equalities $\boldsymbol{F} = 0$ represent the real and reactive power balance equations which must be satisfied. $\boldsymbol{G} \leq 0$ represent constraints on bus voltages and any other constraints such as thermal and stability limits on power flows. $\boldsymbol{\lambda}$ and $\boldsymbol{\mu}$ are the Lagrange multipliers associated with the power balance equations and the line and voltage constraints respectively.

A relationship between the locational prices $\boldsymbol{\lambda}$ and the cost function C at the optimum (denoted by *) is found as:

$$\boldsymbol{\lambda} = -\left.\frac{\partial C}{\partial \boldsymbol{F}}\right|_{*} = \left.\left[\frac{\partial C^T}{\partial \boldsymbol{P}_L} \; \frac{\partial C^T}{\partial \boldsymbol{Q}_L}\right]^T\right|_{*} \tag{2.10}$$

where $\boldsymbol{P}_L$ and $\boldsymbol{Q}_L$ are real and reactive load vectors. Similarly $\boldsymbol{\mu}$ reveals the marginal change in costs with respect to the line and voltage constraints.

By introducing a reference bus (denoted by subscript r) it is possible to decompose the locational price into a component for generation and losses and a component due to transmission congestion. The above problem then has the equivalent representation:

$$\begin{aligned}
&\min_{P_G, Q_G, V, \theta} C(\boldsymbol{P}_G) \\
&\text{s.t.} \\
&\boldsymbol{f}(\boldsymbol{P}_{Gr}, \boldsymbol{Q}_{Gr}, V_r, \theta_r, V, \theta) = 0 \quad (\boldsymbol{\lambda}_r) \\
&\boldsymbol{F}(\boldsymbol{P}_G, \boldsymbol{Q}_G, V_r, \theta_r, V, \theta) = 0 \quad (\boldsymbol{\lambda}) \\
&\boldsymbol{G}(\boldsymbol{P}_G, \boldsymbol{Q}_G, V_r, \theta_r, V, \theta) \leq 0 \quad (\boldsymbol{\mu})
\end{aligned} \tag{2.11}$$

In this formulation the variables without subscripts $(\boldsymbol{P}_G, \boldsymbol{Q}_G, V, \theta)$ do not include variables for the reference bus. The first set of equality constraints, $\boldsymbol{f} = 0$, explicitly identifies the power injection equations associated with the reference bus. Under the satisfaction of certain regularity assumptions (Gribik et al., 1990) this problem is solvable. By using the dual formulation of the problem, Equation (2.11), the equality constraints can be expressed as:

$$\begin{aligned}
(\nabla_V \boldsymbol{f})^T \boldsymbol{\lambda}_r + (\nabla_V \boldsymbol{F})^T \boldsymbol{\lambda} + (\nabla_V \boldsymbol{G})^T \boldsymbol{\mu} = 0 \quad (V) \\
(\nabla_\theta \boldsymbol{f})^T \boldsymbol{\lambda}_r + (\nabla_\theta \boldsymbol{F})^T \boldsymbol{\lambda} + (\nabla_\theta \boldsymbol{G})^T \boldsymbol{\mu} = 0 \quad (\theta)
\end{aligned} \tag{2.12}$$

where now V and θ are the Lagrange multipliers of the equality constraints in the dual. Solving these equations for $\boldsymbol{\lambda}$ gives:

$$\boldsymbol{\lambda} = \begin{bmatrix} (\nabla_V \boldsymbol{F})^T \\ (\nabla_\theta \boldsymbol{F})^T \end{bmatrix}^{-1} \begin{bmatrix} (\nabla_V \boldsymbol{f})^T \\ (\nabla_\theta \boldsymbol{f})^T \end{bmatrix} \boldsymbol{\lambda}_r + \begin{bmatrix} (\nabla_V \boldsymbol{F})^T \\ (\nabla_\theta \boldsymbol{F})^T \end{bmatrix}^{-1} \begin{bmatrix} (\nabla_V \boldsymbol{G})^T \\ (\nabla_\theta \boldsymbol{G})^T \end{bmatrix} \boldsymbol{\mu} \tag{2.13}$$

If the reference bus can be said to have prices $\boldsymbol{\lambda}_r$ for real and reactive power that depend only on real and reactive power generation and losses and not transmission congestion, then the generation and loss component and the congestion component of all other locational prices can be identified as:

$$\boldsymbol{\lambda} = \boldsymbol{\lambda}_{GL} + \boldsymbol{\lambda}_C$$

$$\boldsymbol{\lambda}_{GL} = \begin{bmatrix} (\nabla_V \boldsymbol{F})^T \\ (\nabla_\theta \boldsymbol{F})^T \end{bmatrix}^{-1} \begin{bmatrix} (\nabla_V \boldsymbol{f})^T \\ (\nabla_\theta \boldsymbol{f})^T \end{bmatrix} \boldsymbol{\lambda}_r \quad \text{and} \quad \boldsymbol{\lambda}_C = \begin{bmatrix} (\nabla_V \boldsymbol{F})^T \\ (\nabla_\theta \boldsymbol{F})^T \end{bmatrix}^{-1} \begin{bmatrix} (\nabla_V \boldsymbol{G})^T \\ (\nabla_\theta \boldsymbol{G})^T \end{bmatrix} \boldsymbol{\mu} \tag{2.14}$$

When no congestion is present, the price of electricity at a bus only depends on generation and losses. As pointed out by Finney et al. (1997) the choice of the reference bus must be such that it has no congestion component. A natural choice is the bus with the lowest generator costs and available generation capacity.

An alternative to implement the above model is to use a software package such as MATPOWER where a full AC-model can be utilized. Nonlinear programming solution methods are used to calculate the locational prices.

2.3.6.3 Hogan's model and locational prices

The economic dispatch problem as formulated by Hogan (2002b) is:

$$\underset{\boldsymbol{Y},\boldsymbol{u}\in \mathrm{U}}{\text{Max}}\; B(\boldsymbol{d}-\boldsymbol{g}) \tag{2.15}$$

s.t.

$$\boldsymbol{Y} = \boldsymbol{d} - \boldsymbol{g} \tag{2.16}$$

$$L(\boldsymbol{Y},\boldsymbol{u}) + \boldsymbol{\tau}^T \boldsymbol{Y} = 0 \tag{2.17}$$

$$\boldsymbol{K}(\boldsymbol{Y},\boldsymbol{u}) \leq 0 \tag{2.18}$$

where $\boldsymbol{d}$ and $\boldsymbol{g}$ are the vectors of load and generation at the different locations. The variable $\boldsymbol{Y}$ represents the vector of real power bus net loads, including the swing bus s and the vector of remaining net loads $\vec{\boldsymbol{Y}}$ $(\boldsymbol{Y}^T = (Y_s, \vec{\boldsymbol{Y}}^T))$. $B(\boldsymbol{d}-\boldsymbol{g})$ is the net benefit function,[31] and $\boldsymbol{\tau}$ is a unity column vector, $\boldsymbol{\tau}^T = (1,1,....,1)$. All other parameters are represented in the vector of control variables $\boldsymbol{u}^T = (\boldsymbol{Y}_Q, \boldsymbol{t}, \boldsymbol{\alpha})^T$ where $\boldsymbol{Y}_Q$ is the reactive power, $\boldsymbol{t}$ is the transformer tap ratio and $\boldsymbol{\alpha}$ the ideal transformer phase angle shift.[32] The objective Equation (2.15) includes the maximization of benefit to loads and the minimization of generation costs. Equation (2.16) denotes the net load as the difference between load and generation. Equation (2.17) is a loss balance constraint where $L(\boldsymbol{Y},\boldsymbol{u})$ denotes the losses in the network. In Equation (2.18) $\boldsymbol{K}(\boldsymbol{Y},\boldsymbol{u})$ is a vector of power flows in the lines, which are subject to transmission capacity limits. The corresponding multipliers or shadow prices for the constraints are $(\boldsymbol{P}, \boldsymbol{\lambda}_{ref}, \boldsymbol{\lambda}_{tran})$ for net loads, reference bus energy (or loss balance), and transmission constraints,

[31] Function B is typically a measure of welfare, such as the difference between consumer surplus and generation costs (Hogan, 2002b).

[32] Control variables could be generator voltage, phase shift transformer tap position, switched capacitor settings, reactive injection for static VaR compensator, load shedding, DC line flow and load tap changer transformer tap position (Wood and Wollenberg, 1996).

respectively. When security constraints are taken into account (n-1 criterion) this is a large-scale problem, and it prices anticipated contingencies through the security-constrained economic dispatch. The basic idea in the n-1 security-constrained dispatch is to identify a potential set of contingencies typically representing a loss of a single[33] line or generator so that the dispatch still would be within security limits after the outage.

Hogan's model assumes three simplifications (Hogan, 2002b). First, it is assumed that all transmission constraints are defined through the net loads at the buses. In practice, transmission constraints may have a different effect on load and generation.[34] The second simplification consists of focusing on the real power part of the problem. This is convenient in the case that there are no direct costs of producing reactive power and the dispatch of this is given to the system operator. Finally, generation operating reserves are ignored.

The locational prices are the marginal generation cost or the marginal benefit of load which in turn equals the reference price of energy plus the marginal cost of losses and congestion. With the optimal solution $(\boldsymbol{d}^*, \boldsymbol{g}^*, \boldsymbol{Y}^*, \boldsymbol{u}^*)$ and the associated shadow prices, we have the vector of locational prices $\boldsymbol{P}$ as:

$$\boldsymbol{P}^T = \nabla C(\boldsymbol{g}^*) = \nabla B(\boldsymbol{d}^*) = \lambda_{ref}\boldsymbol{\tau}^T + \lambda_{ref}\nabla L_{\boldsymbol{Y}}(\boldsymbol{Y}^*, \boldsymbol{u}^*) + \boldsymbol{\lambda}_{tran}^T \nabla \boldsymbol{K}_{\boldsymbol{Y}}(\boldsymbol{Y}^*, \boldsymbol{u}^*) \tag{2.19}$$

If losses are ignored, it is only the energy price at the reference bus and marginal cost of congestion that contribute. In the PJM market design the locational prices are defined ignoring the system losses (DC load flow), while in New York the locational prices are calculated based on an AC network with marginal losses.

In the presence of transmission congestion, the system operator receives a rent because net payments from loads exceed net payments to the generators. Similarly, as long as pricing is based on marginal losses the grid company will have a merchandizing surplus on this activity.[35] The system operator receives a merchandizing surplus MS that includes payments for transmission congestion and losses. It is calculated as:

$$MS = \sum_{i=1}^{N} P_i d_i^* - \sum_{i=1}^{N} P_i g_i^* = \sum_{i=1}^{N} P_i y_i^* \tag{2.20}$$

where the summation is over the number of buses N in the transmission network.

2.3.6.4 DC-equivalent model and AC approximation model

The DC-load model assumes no real power losses and reactive power loads. The basic assumptions are that the voltage magnitudes are equal to 1.0 since there is

[33] Loss of multiple lines or generators simultaneously would be defined as a single outage.
[34] This can be modeled by introducing different buses for generators and loads connected by a zero impedance line. Different prices for generation and load would also be obtained.
[35] It is assumed that the grid company absorbs all costs, including losses and buys electricity in the market to compensate for losses hour by hour.

sufficient reactive power and the voltage angle differences across the lines are small. Similarly, the transformer phase angle settings are at zero angle $(\boldsymbol{\alpha}=0)$ and the transformer tap ratios are fixed $(\boldsymbol{t}=0)$.

We use Hogan's (2002b) formulation.

Define:

n_B: the number of buses,

n_L: the number of transmission lines,

Ω: the diagonal matrix of line transfer factors, $\Omega_k = x_k / (r_k^2 + x_k^2)$ where r is resistance and x reactance for line k,

R: the diagonal matrix of line resistances,

A: the oriented line-node incidence matrix with elements of 0, 1, -1 corresponding to the network interconnections, For example if line k originates at bus i and terminates at bus j, then $a_{ki} = 1 = -a_{kj}$,

$|A|$: the matrix of absolute values of the network incidence matrix,

$\boldsymbol{C}$: n_L vector of transmission line capacities,

$\boldsymbol{\tau}$: n_B unity column vector,

$\boldsymbol{d}$: n_B vector of loads,

$\boldsymbol{g}$: n_B vector of generation,

$\vec{\boldsymbol{Y}}$: n_B-1 vector of net active power bus loads, $\boldsymbol{Y}^T = (Y_s, \vec{\boldsymbol{Y}}^T)$ where Y_s is the net load at the swing bus, $\boldsymbol{Y} = \boldsymbol{d} - \boldsymbol{g}$,

$\boldsymbol{\delta}$: n_B vector of voltage angles relative to the swing bus, where the swing bus, s, has an angle that equals zero (δ_s=0),

$\boldsymbol{z}$: n_L vector of line flows

The DC-load economic dispatch can be formulated as:

$$
\begin{aligned}
&\operatorname*{Max}_{\boldsymbol{Y},\boldsymbol{z},\boldsymbol{\delta}} B(\boldsymbol{d}-\boldsymbol{g}) \\
&\text{s.t.} \\
&\boldsymbol{Y} = -A^T \boldsymbol{z} \\
&\boldsymbol{z} = \Omega A \boldsymbol{\delta} \\
&\delta_s = 0 \\
&\boldsymbol{z} \le \boldsymbol{C}
\end{aligned}
\tag{2.21}
$$

By eliminating the angles another linear equation for the DC-load formulation can be obtained[36] with the matrix of power transfer distribution factors (PTDFs) as:

$$H = \nabla \boldsymbol{K}_Y(0, \boldsymbol{u}^0)$$

where $\boldsymbol{u}^0$ is a choice of controls that yield full decoupling between the real and reactive power flow and no transmission losses (Hogan, 2002b). Under the DC-load

[36] By combining two of the equations in the program, Equation (2.21), we get $\boldsymbol{Y} = -A^T \Omega A \boldsymbol{\delta}$ and solving this for $\boldsymbol{\delta}$ and substituting it in the second constraint yields $\boldsymbol{z} = H\boldsymbol{Y} = \Omega A (A^T \Omega A)^{-1} \boldsymbol{Y}$ where H is the matrix of power transfer distribution factors.

approximations $H = (0\ \overline{H})$ where $\overline{H} = -\Omega\overline{A}(\overline{A}^T\Omega\overline{A})^{-1}$ with the swing bus dropped in defining $\overline{A}$.[37] Although the matrix *A* is sparse, the matrix *H* is dense and this means that almost every net load affects almost every line. Calculating the PTDFs for a particular line in a particular contingency is about the same amount of work as finding a DC-load flow for that contingency. For a given contingency the net loads and the angles are linked by a relatively sparse matrix $A^T\Omega A$ so that $\boldsymbol{Y} = -A^T\Omega A\boldsymbol{\delta}$. The matrix has only non-zero elements for buses that are directly connected. Given the vector of net loads, it requires no more work to solve for the vector of angles, than finding a particular solution for a set of linear equations. This generally requires much less work than solving for the full matrix inverse and is done quickly in advanced optimization algorithms that use sparse matrix techniques (Hogan, 2002b). Once the vector of angles is known for a given vector of net loads, it is easy to perform one matrix multiplication to obtain the complete load flow in $\boldsymbol{z}$ for each contingency. This illustrates the simplicity of evaluating a particular load flow, compared to calculating the full PTDF matrix, H.

Based on these approximations the problem in Equation (2.21) can be restated as:

$$\begin{aligned}
&\underset{\boldsymbol{Y}}{\text{Max}}\, B(\boldsymbol{d}-\boldsymbol{g}) \\
&\text{s.t.} \\
&\boldsymbol{\tau}^T\boldsymbol{Y} = 0 \\
&H\boldsymbol{Y} \le \boldsymbol{b}
\end{aligned} \tag{2.22}$$

where $\boldsymbol{b} = -\boldsymbol{K}(0, \boldsymbol{u}^0)$. The matrix *H* for the full security-constrained dispatch is very large and dense, and solution methods utilize relaxation algorithms (see Hogan, 2002b) so as to avoid unnecessary calculations of the matrix elements of *H* and only take into account binding constraints (Hogan, 2002b). Additionally, the DC load model is convex and the relaxation algorithm will ensure convergence to a global optimum.

An alternative formulation is to use an AC approximation model. This is done by approximating losses by a term proportional to the square of power flows (Hogan, 2002b):

$$\begin{aligned}
&\underset{\boldsymbol{Y},\boldsymbol{z},\boldsymbol{\delta}}{\text{Max}}\, B(\boldsymbol{d}-\boldsymbol{g}) \\
&\text{s.t.} \\
&\boldsymbol{Y} = -A^T\boldsymbol{z} - \frac{1}{2}|A|^T R\boldsymbol{z}^2 \\
&\boldsymbol{z} = \Omega A\boldsymbol{\delta} \\
&\delta_s = 0 \\
&\boldsymbol{z} \le \boldsymbol{C}
\end{aligned} \tag{2.23}$$

In this formulation the generation (generation less load) equals losses, $\boldsymbol{\tau}^T(\boldsymbol{g}-\boldsymbol{d}) = \boldsymbol{\tau}^T R\boldsymbol{z}^2$, and the problem is no longer linear. However, it is possible to study the combined effects of losses and congestion. Note that the inverse

[37] This is done to remove the singularity which is introduced because the overall energy-balance relationship is included in the specific power flow conservation relationship.

linearization of the solution in terms of the net loads would differ from the pure DC-load approximation.

2.3.7 Comparison of models

This section compares the Wangensteen model, the optimal power flow model and the Hogan model.

The Wangensteen model is characterized by:

- Objective function: maximum social welfare
- Constraints: power flow equations and transmission capacity constraints
- Control variables: active generation and load
- State variables: voltage
- Constraint variables: Lagrange multipliers associated with the power flow equations and the transmission capacity constraints
- Reference bus: choose a fixed voltage for one bus
- Load: elastic
- Computational procedure: solve the Kuhn-Tucker conditions as a set of matrix equations or utilize a Gauss-Seidel procedure (see Wood and Wollenberg, 1996)
- Practical use: educational purposes
- Locational price calculation: price equals marginal cost which in turn equals marginal benefit to load, the prices are equal to the Lagrange multipliers associated with the power flow equations

The modified optimal power flow model is characterized by:

- Objective function: minimum generator costs
- Constraints: power flow equations, transmission capacity, and voltage constraints
- Control variables: active and reactive generation
- State variables: voltage magnitudes and angles
- Constraint variables: Lagrange multipliers associated with the power flow equations and the transmission capacity constraints
- Reference bus: choose fixed voltage magnitude and angle for one bus
- Load: inelastic
- Computational procedure: nonlinear programming methods
- Practical use: widely used in short-term power scheduling
- Locational price calculation: price equals marginal cost which in turn equals marginal benefit to load, prices equal the marginal costs of generation and losses (proportional to the Lagrange multiplier associated with power balance equation for the reference bus) and the marginal costs of congestion (proportional to the Lagrange multipliers associated with the transmission constraints)

The Hogan model is characterized by:

- Objective function: maximum social welfare
- Constraints: bus net loads, loss balance constraint, and transmission capacity constraints
- Control variables: active generation and load, reactive generation and load, transformer tap ratios, and ideal transformer phase angle shifts
- State variables: voltage magnitudes and angles

- Constraint variables: Lagrange multipliers associated with the net load equations, the power flow equations, and the transmission capacity constraints
- Reference bus: choose fixed voltage magnitude and angle for one bus
- Load: elastic
- Computational procedure: nonlinear programming methods
- Practical use: locational pricing systems
- Locational price calculation: price equals marginal cost which in turn equals marginal benefit to load, prices equal the Lagrange multipliers associated with the net load equations which in turn equal the reference bus electricity price (equals the Lagrange multiplier associated with the reference bus energy constraint), the marginal costs of losses (proportional to the Lagrange multiplier associated with the reference bus energy constraint), and the marginal costs of congestion (proportional to the Lagrange multipliers associated with the transmission constraints)

The similarities among the models are that all can be used in locational pricing systems. In these systems the prices are calculated as the marginal cost which in turn equals the marginal benefit to load.

In the Wangensteen model, the locational price is not decomposed into terms that are proportional with the Lagrange multiplier associated with the transmission capacity constraints. The prices are equal to the multipliers associated with the power flow equations. However, when congestion is present they will be affected through Kuhn-Tucker conditions such that the locational prices will increase at electricity deficit locations where more generation must be scheduled and decrease in surplus locations where generation must be backed down. Similarly, in the OPF original formulation the locational prices equal the multiplier associated with the power balance constraint.

On the contrary Hogan's model expresses the locational prices as the Lagrange multipliers associated with the net load equations which in turn equal the reference bus electricity price (equals the Lagrange multiplier associated with the reference bus energy constraint), the marginal costs of losses (proportional to the Lagrange multiplier associated with the reference bus energy constraint), and the marginal costs of congestion (proportional to the Lagrange multipliers associated with the transmission constraints). Likewise, the modified OPF model can re-expressed so that the locational prices equal the marginal costs of generation and losses (proportional to the Lagrange multiplier associated with power balance equation for the reference bus) and the marginal costs of congestion (proportional to the Lagrange multipliers associated with the transmission constraints).

The Wangensteen model is used for educational purposes and considers elastic load. The OPF model has been widely used in electrical engineering and dispatch of power systems. Load is assumed to be inelastic. Hogan's model is an economist's version of the OPF model and considers elastic load. It also gives an expression for the locational prices in terms of an equilibrium equation.

2.3.8 Solution methods for economic dispatch and optimal power flow model

The OPF and the economic dispatch models are very large mathematical programming problems that must be solved periodically. Available solution methods are:

- Lambda iteration method
- Gradient methods
- Newton's method
- Linear programming method
- Interior point method

These will not be discussed here, but Wood and Wollenberg (1996) provide an overview of these methods.

2.4 Transmission congestion derivatives

This section describes the financial derivatives that can be used for hedging against transmission congestion under different transmission pricing systems. It describes financial transmission rights in locational pricing systems, Contracts for Differences in area pricing systems, and futures contracts in locational or Chao-Peck pricing systems.

2.4.1 Financial transmission rights

Stochastic locational prices resulting in uncertain congestion charges create a demand by risk-averse market players for locational price hedging instruments. One such instrument is financial transmission rights (FTRs). The congestion rents that the ISO collects are redistributed to the market players through FTRs (Hogan, 1992).

Because electricity flows according to Kirchoff's laws and is difficult to trace, it is difficult to define and manage transmission usage. The first transmission capacity definition was a contract path fiction, which then evolved into flow-based paths. However because such a transaction involves the purchasing of several hedges against flowgates[38] (Hogan, 2002a), an alternative approach is the point-to-point definition with implicit flows. Likewise, Joskow and Tirole (2000) have demonstrated analytical superiority of FTRs over physical rights.

An FTR gives the holder its share of congestion rents that the ISO receives during transmission congestion. The amount of issued FTRs is decided ex ante and allocated by the ISO to holders based on preferences and estimates of future transmission capacity. The difference between the congestion rent and payments to FTR holders may be positive, resulting in a surplus to the ISO. The surplus is redistributed to FTR holders and transmission service customers. On the contrary, if payments to FTR holders exceed the congestion rent, the ISO reduces payments proportionally to FTR holders or requires that the transmission owners make up the deficit. The allocation of FTRs typically occurs as an auction, but FTRs may also be allocated to transmission service customers who pay the embedded costs of the transmission system. The

[38] A modeled transmission line or transformer that can become limiting during system operation. A flowgate may consist of the total interface between control areas, a partial interface, an interface within a control area that consists of a single line or transformer, or a defined set of any of these facilities.

design of the auction is decided by the ISO and depends on the market structure. FTRs entitle (or obligate) the holder to the difference in locational prices times the contractual volume. The mathematical formulation for the payoff is:

$$\text{FTR} = Q_{ij}(P_j - P_i) \tag{2.24}$$

where P_j is the bus price at location j, P_i is the bus price at location i and Q_{ij} is the directed quantity specified for the path from i to j. An FTR obligation may be viewed as an injection Q_{ij} of electricity at bus i and a withdrawal of Q_{ij} at bus j. If the contractual volume matches the actual traded volume between two locations, an FTR is a perfect hedge against volatile locational prices.

FTRs can take different forms such as point-to-point FTRs and flowgate FTRs both of obligation and option type (Hogan, 2002b). Flowgate FTRs are constraint-by-constraint hedges that give the right to collect payments based on the shadow price associated with a particular transmission constraint (flowgate). Hogan (2002b) argues that point-to-point obligation FTRs have been demonstrated to be the most feasible hedging instrument in practice. However, for point-to-point option FTRs the computational demands are more substantial, but they have been introduced in PJM in 2003. Flowgate rights have been used in California[39] and Texas. Point-to-point obligations can be either balanced or unbalanced, where the balanced type is a perfect hedge against transmission congestion and the unbalanced type is a hedge against losses (represented as a forward sale of energy).

The flowgate rights approach has been proposed by Chao and Peck (1996 and 1997) and is based on a decentralized market design. Stoft (1998) demonstrated that having liquid futures markets for k "Chao-Peck prices" would completely hedge against transmission risk in k flowgates. The flowgate proponents claim that the point-to-point approach does not provide effective hedging instruments because the point-to-point FTR markets may work inefficiently in practice. Oren (1997) argues that they result in price distortions and inefficient dispatch. Therefore, the proponents propose the alternative of using a decentralized congestion management scheme that facilitates the trading of flowgate rights. The idea behind flowgates is that since electricity flows along many parallel paths, it may be natural to associate the payments with the actual electricity flows. Key assumptions include a power system with few flowgates or constraints, known capacity limits at the flowgates and known power transfer distribution factors (PTDFs) that decompose a transaction into the flows over the flowgates. In practice, however, this may not be the case. The physical rights approach has been abandoned and a financial approach has been proposed in the literature (Hogan, 2002b). The payoff from the FGRs is determined by taking the associated flowgate shadow price times the flowgate amount and totaling them for all lines k that are affected by the transaction between buses m and n (Equation (2.25)).

[39] The flowgate in California has both a physical and a financial aspect.

$$
\begin{aligned}
&\text{FGR} = \sum_k \eta_k f_k^f \\
&\eta_k = \text{shadow price} \\
&f_k^f = \left(\nabla \boldsymbol{K}_{\boldsymbol{Y}}(\boldsymbol{Y}^*, \boldsymbol{u}^*)\right)_{kmn} Q_k = \text{the flowgate amount} \\
&\left(\nabla \boldsymbol{K}_{\boldsymbol{Y}}(\boldsymbol{Y}^*, \boldsymbol{u}^*)\right)_{kmn} = \text{ the PTDF at the optimal operating point } (\boldsymbol{Y}^*, \boldsymbol{u}^*) \\
&\text{for a transaction between buses } m \text{ and } n \text{ over line } k \\
&Q_k = \text{contract quantity}
\end{aligned}
\qquad (2.25)
$$

The flowgate amount can take negative, zero or positive values.

In general, parties that want to be fully hedged should purchase a mix of FGRs that matches the distribution of flows from its transaction.[40] In a transmission network, the flows will be determined by the line impedances, and more than one flowgate (transmission constraint) may be affected. Flowgate rights proponents assert that trading is easy if there are few commercially significant flowgates, resulting in a limited set of FGRs and if the PTDFs change infrequently (Chao et al. 2000). This seems difficult to ensure in a dynamic power system where unanticipated transmission constraints may become binding (Hogan, 2000 and Ruff, 2001). Furthermore, they argue that a more efficient congestion market will enable a more efficient energy market.

The allocation of point-to-point obligation FTRs usually takes place in auctions, where the benefit function of the buyer or seller is maximized. The benefit function is assumed to be concave and differentiable and is optimized subject to all relevant system constraints. The auction determines the allocated amount of FTRs to market players and market clearing prices. It is also a mechanism for reconfiguration of FTRs.

To further stimulate reconfiguration and liquidity FTRs can be traded in secondary markets. It may happen that an FTR between two locations is non-existent. Then it may be possible to combine other FTRs to synthetically construct the non-existent FTR. FTRs may have duration from months to years.

2.4.1.1 Revenue adequacy and simultaneous feasibility

A central issue in the provision of FTRs by an ISO is revenue adequacy. To maintain the credit standing of the ISO who is the counter party, the set of FTRs must satisfy the simultaneous feasibility conditions that are governed by the transmission system constraints. Revenue adequacy means that the revenue collected with locational prices in the dispatch should at least be equal to the payments to the holders of FTRs in the same period. Each time there is a change in the configuration of FTRs, the simultaneous feasibility test must be run to ensure that the transmission system

[40] This assumes that all constraints that could have been binding in the dispatch have been designated as flowgates, and that the ISO has made FGRs available for all flowgates. If some constraints have not been designated, but become binding, then there is no mechanism by which parties can purchase a perfect hedge. Some proposals for FGRs take this into account by not charging holders for the non-predicted constraints and instead socialize the costs.

can support the set of issued FTRs. If the set of FTRs is simultaneously feasible, then they are revenue adequate. This has been demonstrated for lossless networks by Hogan (1992), extended to quadratic losses by Bushnell and Stoft (1996), and further generalized to smooth nonlinear constraints by Hogan (2000). As shown by Philpott and Pritchard (2004) negative locational prices may cause revenue inadequacy. In the general case of an AC or DC formulation the transmission constraints must be convex to ensure revenue adequacy (O'Neill et al., 2002; Philpott and Pritchard, 2004).

The FTR market is operated in parallel with the spot market, and to ensure revenue adequacy the net demands from the FTRs must satisfy the power flow equations, the loss balance constraint and the transmission capacity constraints. A security-constrained optimal power flow model is utilized and contingency constraints may be numerous. However, practical experience from PJM and New York shows that software can solve this problem. Under a spot market and load equilibrium, revenue adequacy is obtained for point-to-point obligation FTRs, when the implied power flows from these are simultaneously feasible. Revenue adequacy is the financial counterpart of available transmission capacity (Hogan, 2002b). Mathematically we state the simultaneous feasibility test as:

$$\begin{aligned} &\boldsymbol{Y} = \sum_k \boldsymbol{t}_k^f \\ &L(\boldsymbol{Y},\boldsymbol{u}) + \boldsymbol{\tau}^T\boldsymbol{Y} = 0, \\ &\boldsymbol{K}(\boldsymbol{Y},\boldsymbol{u}) \le 0 \end{aligned} \tag{2.26}$$

where $\sum_k t_k^f$ is the set of point-to-point obligations.[41] When including security constraints, this becomes a large-scale feasibility problem. The feasibility test is included in the auction formulation and pricing and trading of FTRs is done through a centralized period auction. Every FTR has an implied power flow, and the simultaneous interaction among the FTRs through the auction makes the FTR prices and the congestion fees hedged by these FTRs interrelated.

The model grid that represents expected conditions may be an inaccurate description of the grid offered for dispatch, resulting in discrepancies between the congestion charges and the payoff to the holders of FTRs. Currently, the ISO redistributes excess congestion charges to the FTR holders in deficit payment periods and transmission service customers. Conversely, when there are deficit congestion charges, the ISO may reduce payments proportionally to FTR holders or require transmission owners to make up the deficit.

Oren et al. (1995) and Oren and Deng (2003) argue that the simultaneous feasibility test is too strict. The argument is that because most tradable commodities trade in higher volumes than the underlying physical delivery, it is reasonable to

[41] Generally we could decompose $\sum_k t_k^f$ into a set of balanced $\sum_k \tau_k^f$ and unbalanced $\sum_k \bar{g}_k^f$ obligations such that $Y = \sum_k \tau_k^f - \sum_k \bar{g}_k^f$, see Hogan (2002b). The unbalanced obligations are injections of energy.

assume that this is also true for FTRs. However, the feasibility condition has importance in allocating new FTRs to investors as demonstrated by Bushnell and Stoft (1997). Oren and Deng (2003) propose that the revenue adequacy requirement should be relaxed to a seasonal or annual accounting, or a value at risk approach.

2.4.1.2 Critique of the financial transmission rights model

Joskow and Tirole (2002 and 2003) provide an extensive critique of the short-run FTR model and its ability to create proper incentives for transmission investment. They argue that the FTR model is based on strong assumptions of perfect competition that allows efficiency. The assumptions include:

- no increasing returns to scale
- no sunk costs
- locational prices that fully reflect consumers' willingness to pay
- network externalities internalized by locational prices
- no uncertainty in congestion rents
- no market power so that markets are always cleared by prices
- complete futures markets
- ISO with no inter-temporal preferences regarding effective transmission capacity

The FTR model then allows investment in transmission to compete with investments in generation and provides a solution to the natural monopoly regulatory problem (Joskow and Tirole, 2002). However, if some of the above assumptions are not valid, the FTR model no longer creates proper incentives to prevent transmission congestion. In particular this is demonstrated by Léautier (2000) under a pay-as-bid pool rule where generators holding FTRs have incentives to reduce transmission capacity to enhance local market power. Similar results are found for physical transmission rights (Bushnell, 1999; Joskow and Tirole, 2000).

Joskow and Tirole (2003) have the following criticisms regarding the short-run FTR model:

- Market power raises prices in constrained area so that prices do not reflect marginal costs. Generators in a constrained region tend to withhold output to raise their price. The higher market-clearing prices therefore overestimate the benefits from the financial transmission rights.
- Existing and incremental transmission capacities are not well-defined and are stochastic.
- Separation of transmission ownership and system operation creates a moral-hazard problem of type "in teams."[42]
- The initially feasible set of FTRs may depend on uncertain exogenous variables.

Perez-Arriaga et al. (1995) point out that revenues from locational pricing only cover 25% of total costs. It is therefore necessary to combine FTRs with a fixed-price structure to recover fixed costs.

According to Hogan (2003) contingencies outside the control of the ISO could lead to revenue inadequacy, but such cases are rare and non-representative. Most

[42] An outage can be claimed to result from poor maintenance (by the transmission owner) or from ill-judged dispatch (by the ISO).

contingencies are anticipated by running an N-1 security-constrained dispatch where the outage of a line or a generator is taken into account. Then the power flows after an outage would still be feasible in the dispatch.

2.4.1.3 Market power in the financial transmission rights market

Among researchers (Joskow and Tirole, 2000; Léautier, 2001; Gilbert, Neuhoff, and Newbury, 2002) there is consensus about the need to mitigate market power for any FTR auction to be efficient. Joskow and Tirole (2000) study a radial line network under different market structures for both generation and FTRs. They demonstrate that FTR market power by a producer in the importing region (or a consumer in the exporting region) aggravates their monopoly (monopsony) power, because dominance in the FTR market creates an incentive to curtail generation (demand) to increase the value of the FTRs. This is also in line with the conclusion in the FTR literature: generators can more easily exert local market power when transmission congestion is present (Bushnell, 1999; Bushnell and Stoft, 1997; Joskow and Tirole, 2000; Oren, 1997; Joskow and Schmalensee, 1983; Chao and Peck, 1997; Gilbert, Neuhoff, and Newbery, 2002; Cardell, Hitt, and Hogan, 1997; Borenstein, Bushnell and Stoft, 1998; Wolfram, 1998; Bushnell and Wolak, 1999). The behavior of the generators in the FTR market should then be regulated.

Allocation of FTRs to a monopoly generator depends on the structure of the market (Joskow and Tirole, 2000). When the FTRs are allocated initially to a single owner that is neither a generator nor a load, the monopoly generator will want to acquire all FTRs. When all FTRs initially are distributed to market players without market power, the generator will buy no FTRs. When the FTRs are auctioned to the highest bidders, the generator will buy a random number of FTRs. Extending this analysis, Gilbert, Neuhoff, and Newbury (2002) analyze ways of preventing perverse incentives by identifying conditions where different FTR allocation mechanisms can mitigate generator market power during transmission congestion. In an arbitraged uniform price auction, generators will buy FTRs that mitigate their market power, while in a pay-as-bid auction FTRs might enhance their market power. Specifically, in the radial line case, market power might be mitigated by not allowing generators to hold FTRs related to their own energy delivery. In the three-node case, mitigation of market power implies defining FTRs according to the reference node with the price least influenced by the generation decision of the generator.

In practical implementations of the FTR model, market power mitigating rules are designed (Rosellon, 2003). FERC has included market power mitigation rules in the standard market design (FERC, 2002). FERC indicates that insufficient demand-side response and transmission constraints are the two main sources for market power. FERC differentiates between high prices because of scarcity and high prices resulting from exercising market power. Using a merit-order spot market mechanism FERC proposes to use a bid cap for generators with market power in a constrained region and a "safety net"[43] for demand side response. Regulated generators are also subject to a resource adequacy requirement. Chandley and Hogan (2002) claim that this mechanism is inefficient because the use of penalties for under-contracting (with respect to the resource adequacy requirement) would not permit prices to clear energy

[43] Similar to the $1000 per MWh bid cap in the northeastern and Texas electricity markets (Rosellon, 2003).

and reserve markets. Moreover, long-term contracting should be voluntary, and based on financial hedging, not on capacity requirements.

2.4.2 Nordic Contracts for Differences

A risk management tool against transmission congestion risks in the Nordic market is Contracts for Differences (CfDs).[44] These financial instruments make it possible for the market players to hedge against the difference between the area price and the System Price (the unconstrained price) in a future time period (Nord Pool, 2002). The contracts are available for all spot areas (except within Norway). The forward and futures contracts traded at Nord Pool are with reference to the System Price. Producers are paid the area price for production in their area. Consumers purchase electricity at their respective area price. Often, producers and consumers in different areas encounter situations of transmission congestion when the area prices differ from the System Price.

Congestion fees for bilateral transactions in the Nordic countries are calculated based on the difference between the area prices times the transferred quantity. Usually producers pay the fee, but parties can also make other arrangements.

The payment from the Nordic CfD is:

$$\mathrm{CfD} = Q_i\,(AP_i - SP) \tag{2.27}$$

where AP_i refers to the area price in area i, SP is the System Price, and Q_i is the contracted volume. Payments are calculated as the average of the difference between the daily area price and the System Price during the delivery period (a season or a year) times the contracted volume. From Equation (2.27) we see that each time the area price is higher than the System Price the holder receives a rebate equal to the price differential times the contract quantities. Otherwise, the holder must pay the negative difference.

The market price of a Nordic CfD can be positive, negative or zero (Kristiansen, 2004). CfDs trade at positive prices if the market expects that the area price will be higher than the System Price (a net import situation). CfDs trade at negative prices if the market expects an area price below the System Price (a net export situation).

A perfect hedge using forward or futures contracts is possible only when the area price and the System Price are equal. If forward or futures contracts are used for hedging, this implies a basis risk equal to the area price minus the System Price. To create a perfect hedge against the price differential:

1. Hedge the specified volume by using forward contracts.

[44] Here, the term Contract for Differences is different from the corresponding term used in the British market. In the Nordic region, CfDs are used to hedge against the difference between the two uncertain prices (area price and System Price), not as in the British market, where they hedge the difference between the spot price and a pre-defined reference price or price profile. The Nordic CfD is a locational swap, while the British CfD is settled based on the difference between the spot price and the reference price. When referring to CfD in the Nordic market, the term Nordic CfD is used.

2. Hedge against the price differential – for the same period and volume – by using CfDs.
3. Accomplish physical procurement by trading in the Elspot area of the holder of the contract.

Norway has adopted an area price model to manage congestion in the day-ahead market. A charge equal to the difference between the System Price and low area price times the transferred quantity (capacity charge) is imposed in the low price area, and a charge equal to the difference between the high area price and the System Price times the transferred quantity is imposed in the high price area. Thus, withdrawals are charged in the high price area and compensated in the low price area. The opposite is the case for net injections. However, it is impossible to hedge against price differences within Norway, because there is only one contract with reference to the area Norway 1 (Oslo). Shorter-term products and products for hedging directly against area price differentials are unavailable at the exchange. Nord Pool is considering listing CfDs with reference to Norway 2 (Trondheim) and CfDs with shorter delivery periods such as weeks or months (Nord Pool, 2003). Nord Pool is also considering the listing of CfDs with reference to the German EEX price.

2.4.3 Locational price hedging using the futures markets

The model for this approach has been developed by Rajaraman and Alvarado (1998). In theory, futures or forward markets could be used to hedge locational risks. In practice, there are relatively few liquid futures markets but many locational electricity spot markets. It is possible to manage or eliminate the locational risks by using these few futures markets, by taking a precisely determined position in the futures markets by time 0 and taking another precisely determined position later in the spot markets. The same idea can be used to realize arbitrage opportunities if they are present. The model may be applied in an electricity futures market based on a Chao-Peck congestion pricing scheme where congestion is priced explicitly (Chao and Peck, 1996 and 1997; Stoft 1998). The basic idea is briefly explained here.

The locational spot prices $\boldsymbol{\lambda}$ (N in total – one for each bus) can be described as:

$$\begin{bmatrix} \lambda_1 \\ \dots \\ \lambda_N \end{bmatrix} = \begin{bmatrix} a_{11} & \dots & a_{1,L+1} \\ \dots & \dots & \dots \\ a_{N,1} & \dots & a_{N,L+1} \end{bmatrix} \begin{bmatrix} \eta_1 \\ \dots \\ \eta_{L+1} \end{bmatrix} \Leftrightarrow \boldsymbol{\lambda} = A\boldsymbol{\eta} \tag{2.28}$$

The matrix A has dimension N times $L+1$ and $\boldsymbol{\eta}$ is the shadow price associated with the power flow equations and the transmission capacity constraints. The first column of A describes the effect of transactions on losses. In particular, each element in the column is equal to one plus the percentage of losses involved in incremental transactions that occur between the actual location and the reference location. The remaining columns of A are the power transfer distribution factors (PTDFs) corresponding to each of the flowgates (or possible congested transmission lines). The first element of the vector $\boldsymbol{\eta}$ is the spot price of electricity at the reference bus. The remaining elements are the shadow prices associated with congestion relative to the reference bus for the flowgates.

Rajaraman and Alvarado (1998) describe a risk management strategy where the market player takes a position $\boldsymbol{f}$ at time 0 in the futures markets (for delivery at time T), and a position $\boldsymbol{s}$ in the spot markets at time T to buy and sell obligations $\boldsymbol{p}$ at time T. The portfolio position $\boldsymbol{p}$ can be described as a combination of spot purchases $\boldsymbol{s}$ and futures purchases:

$$\begin{bmatrix} p_1 \\ \dots \\ p_N \end{bmatrix} = \begin{bmatrix} s_1 \\ \dots \\ s_N \end{bmatrix} + \begin{bmatrix} x_{11} & \dots & x_{1M} \\ \dots & \dots & \dots \\ x_{N1} & \dots & x_{NM} \end{bmatrix} \begin{bmatrix} f_1 \\ \dots \\ f_M \end{bmatrix} \Leftrightarrow \boldsymbol{p} = \boldsymbol{s} + X\boldsymbol{f} \tag{2.29}$$

where the matrix element x_{ij} in every column represents the numerical weight of the locational bus prices at a futures market and X is a market portfolio matrix.

The cost (or profit) c to a market player of spot purchases and hedge purchases is given by:

$$c = \boldsymbol{s}^T \boldsymbol{\lambda} + \boldsymbol{f}^T \boldsymbol{p}_f \tag{2.30}$$

where $\boldsymbol{\lambda}$ is the spot price at a bus and $\boldsymbol{p}_f$ is a vector of futures prices with dimension M. Since the futures prices are known at time 0 while the locational bus prices are uncertain this yields:

$$c = \left(\boldsymbol{p}^T A - \boldsymbol{f}^T X^T A\right) \cdot \boldsymbol{\eta} + \boldsymbol{f}^T \boldsymbol{p}_f \tag{2.31}$$

The costs are only subject to uncertainty in locactional prices, since the futures prices are given at time 0. The costs will be minimized when the difference between the two first terms is zero, as given by the condition:

$$\left(\boldsymbol{p}^T A - \boldsymbol{f}^T X^T A\right) = 0 \tag{2.32}$$

This can be performed by taking a position in the futures market $\boldsymbol{f}$ at time 0, and a position $\boldsymbol{p}$-$X\boldsymbol{f}$ in the spot market at time T, such that the difference is zero. The costs of the hedge are $\boldsymbol{f}^T \boldsymbol{p}_f$. In complete markets,[45] the difference is zero for an arbitrary choice of $\boldsymbol{p}$. Equation (2.32) may be viewed as a linear equation in $\boldsymbol{f}$. By studying the dimension of the matrices we find that $X^T A$ has dimensions M by $L+1$, and $\boldsymbol{p}^T A$ is a row vector of dimension $L+1$. If the number of electricity futures markets M is strictly less than one more than the number of flowgates, L+1, then there are too many equations in too few unknowns and the condition will usually[46] not be satisfied. If M is strictly greater than L+1, then there are too few equations in too many unknowns and the condition will be satisfied for many different portfolios $\boldsymbol{f}$. When M is exactly equal to L+1, there will usually be a unique solution $\boldsymbol{f}$. Equation (2.32) will have a solution if $\boldsymbol{p}^T = \boldsymbol{f}^T X^T$. For an arbitrary choice of $\boldsymbol{p}$ this condition will be satisfied if

[45] The term “complete markets” means that the futures markets “span” the set of all possible transmission congestion events.

[46] Synonymous with the phrase “chances are that” (Rajaraman and Alvarado, 1998).

X is invertible, i.e. $M = N$. These results show that perfect hedging is usually possible for any arbitrary obligation $\boldsymbol{p}$ when the number of futures markets equals the number of buses or when the number of futures markets equals one more than the number of flowgates. While risk is perfectly hedged it will not necessarily leave the market player better off than if it had participated only in the spot market.

2.4.4 Pricing of transmission congestion derivatives

Siddiqui et al. (2003) study the prices of transmission congestion contracts in the New York market and find that the TCC prices do not reflect the congestion rents for large exposure hedges and over large distances. These TCC holders pay excessive risk premiums. They argue that this may be due to the way the TCCs are defined with fixed capacity over a fixed period and high transaction costs for disaggregating them in the secondary market. Market players therefore consistently predict transmission congestion incorrectly for all other hedges than the small and straightforward hedges. Also the large number of possible TCCs decreases price discovery. Pricing of TCCs are based on anticipated and feasible congestion patterns which may not be realized in the actual dispatch. This may make TCCs mispriced. However, the pricing of TCCs may be symptomatic of an immature market. Also arbitrage of electricity prices may be impossible because of illiquidity, risk aversion, and regulatory risks (Siddiqui et al., 2003)

Kristiansen (2004) studied the prices of Contracts for Differences in the Nordic market and found that most of the contracts do not reflect the congestion rent. But there are also contracts that underestimate the congestion rent, resulting in a positive payoff to the holders. The Nordic CfDs are traded as forward contracts and do not have any connection to the congestion rent that the transmission system operator collects. The pricing of CfDs could be due to that the CfD market has only been in operation since November 2000 and therefore is immature. The majority of the results are in line with the pricing of futures at Nord Pool (Botterud et al., 2002).

2.5 Transmission investments

Transmission capacity is vital for the development of electricity markets. Shortages could prevent generators from selling electricity at high price locations and result in end users paying higher prices. The development of electricity transmission infrastructure requires adequate incentives to solve short-run congestion management, recuperate long-term fixed costs, and investment to expand the network (Rosellon, 2003). The short-run congestion management is solved by calculating the cost of transmission usage as the difference in locational prices times the transferred quantity. However, there are conflicting objectives of congesting the network in the short-run and expanding it in the long-run. Woolf (2002) and Hunt (2003) present diverging international mechanisms or practices that have been used to solve these issues. The United Kingdom and Norway have applied basic regulation, while the northeastern US has applied a mixture of planning and auctioning of long-term transmission rights. The Australian market uses a combination of regulatory mechanisms and merchant incentives.

Bushnell and Stoft (1997) explain that the external benefits of transmission investments are not appropriable and certain transmission investments might have negative externalities on the capacity of other transmission lines. One way to proceed with this is to let the investor pay for the negative externalities generated by buying back transmission rights from the initial holders.

We can now consider the basic economic theory for merchant transmission investments and then the approach of long-term FTRs for transmission expansion. This section also describes the market power problems associated with transmission expansion.

2.5.1 Merchant transmission investment theory

Network deepening investments are those that involve physical upgrades of the incumbent transmission owner's facilities[47] (Joskow and Tirole, 2003). These investments are physically intertwined with and inseparable from the incumbent transmission owner's facilities and can be undertaken most efficiently by the incumbent network owner. Network maintenance decisions are similar to network deepening investments and also are most efficiently undertaken by the incumbent transmission owner.

Independent network expansion investments are investments that involve the construction of separate new lines (including parallel lines) that are not physically intertwined with the incumbent network except at the point where they are interconnected (Joskow and Tirole, 2003). These investments can be made by incumbent transmission owners, by stakeholders or by third-party merchant investors.

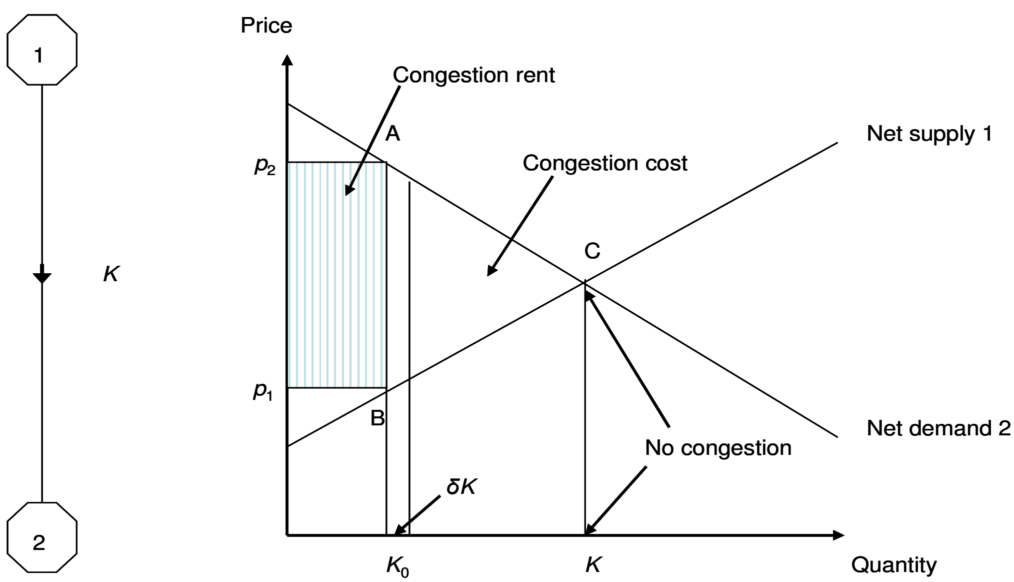

Figure 2-6. Congestion rents and congestion costs.

Figure 2-6 shows a simple radial line where loads at bus 2 buy their consumption at the cheap bus 1 and possibly at the more expensive generators at their local bus (Joskow and Tirole, 2003). The capacity from bus 1 to bus 2 is constrained to K. Based on the net demand/supply curves the system operator is forced to dispatch "out

[47] Examples are capacitor banks, phase shifters, upgrading transformers and substations, and reconductoring existing transmission lines.

of merit" to meet demand. The scarce transmission capacity is reflected in the locational prices p_1 and p_2 that clear the market at bus 1 and bus 2. The difference $\eta = p_2 - p_1$ is the scarcity price of transmission. The area ηK_0 is the congestion rent and the triangle ABC represents the congestion or redispatch cost. The congestion cost represents the cost of running more expensive generation at bus 2 that has to substitute cheap generation at bus 1 because of the transmission constraint. Next, consider a marginal unit increase in transmission capacity δK that allows one more MW to flow from bus 1 to bus 2. It therefore replaces a marginal generator at bus 2 with cost p_2 by a cheaper generator at bus 1 with cost p_1. The social value of this investment is given by the reduction in area ABC in Figure 2-6.

Assume that the builder of this marginal capacity is rewarded with an FTR of value η. A non-incumbent investor will proceed with this investment as long as η exceeds the investment costs. Conversely, an incumbent transmission owner that is compensated through the congestion rent may not want to proceed with this expansion. This will depend on the extra revenue η net of investment costs with the reduction in the congestion rent on its inframarginal transmission units $-Kd\eta / dK$. It is only when the incumbent transmission owner's transmission capacity has been rated at some level K^* not too different from the actual capacity, and that the corresponding FTR with value ηK^*, has been auctioned off, that the monopoly distortion disappears. The incremental capacity then yields $\eta + (K - K^*)\dfrac{d\eta}{dK}$ close to η.

Hogan (1992) and Bushnell and Stoft (1996 and 1997) demonstrate that under certain conditions[48] all efficient transmission investments will at least recover their costs from congestion rents. Likewise, inefficient investments will not be profitable. Joskow and Tirole (2003) argue that the optimality of this market-driven approach depends on several strong assumptions that are unlikely to be found in practice.

At bus 2 which is import constrained the generator may exercise market power by withdrawing output and driving the price up. Then the price p_2 would exceed then marginal cost c_2 at that location. The measured congestion rent then overestimates the cost savings associated with the replacement of one unit of power generated at bus 2 by one unit of power generated at bus 1. Therefore, it results in an over-incentive to expand the line assuming no impact of other potential market imperfections. Conversely, the increased transmission capacity does not replace generation at bus 2 one-for-one so it leads to an increase in total electricity consumption at bus 2, resulting in an increase in social welfare equal to $(p_2 - c_2)$ times the increase in consumption. Joskow and Tirole (2003) demonstrate that the first effect dominates and market power results in an over-incentive to invest in transmission. Similarly, entrants in generation expansion have an over-incentive to invest at bus 2. Summarizing, Joskow and Tirole (2003) find that market power in the importing region produces enhanced incentives for transmission investment.

[48] No increasing returns to scale, simultaneous feasibility constraints bind when allocating FTRs, efficient locational prices clear all markets, no market power in the wholesale market, well defined property rights, a complete set of liquid futures markets.

Conversely, a generator with market power at bus 1 may be able to drive the price p_1 up by withdrawing output (perhaps to the level of p_2 if it faces no competition at bus 1). Then the congestion rent underestimates the benefit from expanding the transmission capacity, resulting in an under-investment by merchant investors (Joskow and Tirole, 2003). Similarly, a price cap at bus 2 could reduce congestion rents during those hours that are important because they produce the majority of the rents to support the investment, resulting in under-investment in transmission.

Network expansion projects are likely to be lumpy. This means that the average cost of a new line decreases as its capacity increases, other things being equal (Baldick and Kahn, 1992; Perez-Arriaga et al., 1995). Many network deepening investments may be less lumpy, but as discussed by Joskow and Tirole (2003) those are more likely to be undertaken by the incumbent network owner rather than a merchant investor.

The impact of lumpiness is illustrated in Figure 2-7. The initial capacity is K_0 and is expanded to K_1. It is assumed that the locational prices are efficient (net demand/supply reflect true marginal costs/willingness to pay) and clear the market. The increase in social surplus $S1$ created by the expansion is illustrated by the shaded area in Figure 2-7. This is also equal to the reduced redispatch costs. The value of the FTR is $\eta_1(K_1 - K_0)$, equals the ex post congestion rent and is rewarded to the merchant investor. The area $\eta_1(K_1 - K_0)$ is less than the increase in social surplus $S1$. Thus, lumpiness results in an under-incentive for the investor to proceed with the expansion. Likewise, an incumbent network owner that is rewarded by congestion rents has suboptimal incentives to remove these congestion rents.

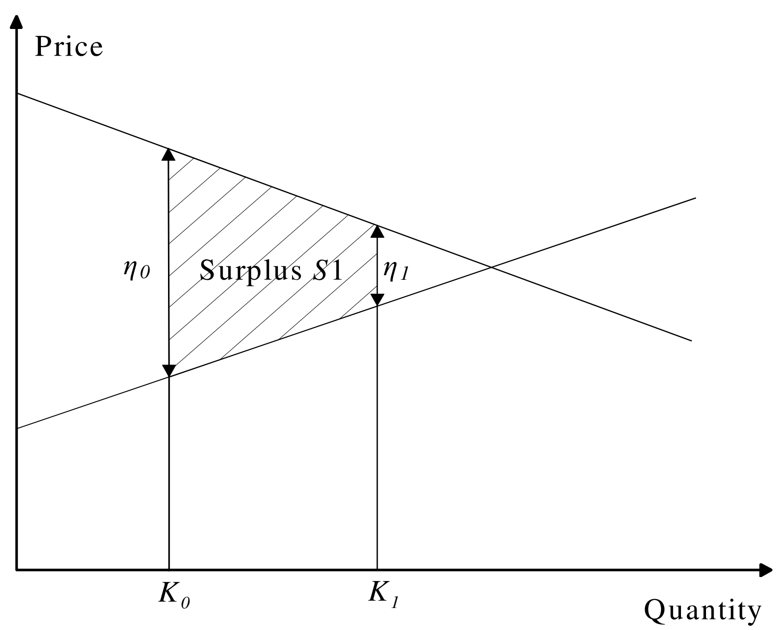

Figure 2-7. Impact of lumpiness.

Lumpiness can also be found when there is scarcity of rights of way, for example a unique corridor between a cheap and an expensive area (Joskow and Tirole, 2003). Merchant investments are then likely to end up in a "pre-emption and monopoly" situation, where the investor builds a small new incremental capacity that is subsequently expanded in network deepening investments. In addition to under-stimulating investments, lumpiness may also make investments occur too early when the objective of the investor is pre-emption of additional entry.

2.5.2 Long-term financial transmission rights for transmission expansion

There are three possible approaches for stimulating investments in transmission expansion: long-term FTRs, price caps, and market power analysis which all build on the equilibrium in the spot market (Rosellon, 2003). We focus on the long-term FTR approach where an ISO allocates through an auction long-term FTRs corresponding to the new economic capacity created. Typical existing FTRs have a duration from one month to five years. However, the life-time of a transmission investment is approximately 30 years. Therefore, the owner of such an investment may prefer to receive a long-term FTR.

The long-term FTR approach is based on a short-run spot market for energy and ancillary services that is operated by the ISO. The spot prices are calculated in a security-constrained economic dispatch. Hogan (2002a) views the approach as a merchant transmission investment because incremental FTRs can provide market-based transmission pricing that may create incentives for transmission investments.

Bushnell and Stoft (1997) indicate that market failures in electricity transmission expansion are because of: 1) market power of a single regional transmission capacity owner, 2) external benefits of transmission investments that are not appropriable, and 3) negative externalities on existing transmission capacity caused by an investment in the network. Specifically Bushnell and Stoft studied expansion in a two-node network where a new line was inserted. They demonstrated that this expansion might violate some of the existing FTRs, and proposed that the investor should pay back to the market players the amount that represents the externalities.

Moreover, Bushnell and Stoft (1997) demonstrate that the value of incremental FTRs allocated under the feasibility rule will be less than or equal to the change in social welfare. If a transmission investment reduces social welfare, the investor has to take incremental FTRs with negative value. However, the investor may benefit from this investment because it has commercial interests of a value that offsets the costs of the negative valued FTRs. To prevent investments that decrease social welfare, market players must hold FTRs that match their net load perfectly and incremental FTRs must be allocated under a feasibility rule.

Hogan (2002a) generalizes and extends Bushnell and Stoft's analysis. He provides some preliminary axioms that could define long-term FTRs. The long-term FTR model assumes market players such as generators, loads, Gridco[49] and marketers interested in transmission expansion. Under the assumption that not all FTRs are

[49] An independent company that owns the grid but does not have responsibility for operating the system. It works in conjunction with a system operator and may be a for-profit or not-for-profit entity.

allocated in the network prior to expansion, the allocation of incremental FTRs should satisfy some criteria. The first is that any incremental FTR should be simultaneously feasible with existing FTRs. The second is that such an incremental FTR should remain feasible given that certain currently allocated FTRs (proxy awards) are preserved. The third is that the investor maximized its objective function and the fourth is that allocation process should apply for decreases and increases in transmission capacity.

As Hogan (2002a) points out, the difficulty is to define proxy awards. To extend the definition beyond radial lines, Hogan proposes defining a proxy award as the best use of the current network along the same direction as the incremental FTR was awarded (including negative and positive awards). There are two possibilities in defining the best use. The first is to maximize the preset proxy preferences in terms of proxy FTRs. The second is to maximize investor preferences and simultaneously minimize the amount of proxy FTRs.

2.5.3 Discussion of the long-term financial transmission rights model

Most electricity markets are by nature volatile and therefore no restructured electricity market in the world has adopted a pure merchant approach (Joskow and Tirole, 2002). The PJM and New York ISOs utilize long-term FTRs, and Australia uses a mixture of regulated and merchant transmission investments (Littlechild, 2003). Argentina also uses the hybrid approach under a locational pricing scheme.

Joskow and Tirole (2003) have the following criticisms regarding the long-term FTR model:

- Lumpiness in transmission investments makes payments to investors less than the increase in social surplus.
- Transmission investments are dynamic, and there is no perfect coordination of interdependent investments in generation and transmission. Supply and demand are stochastic and therefore locational prices are stochastic.
- The assumption about equal access to investment opportunities is not good because upgrading of the incumbent's network can only be efficiently put through by the incumbent.
- Inserting a new transmission line might have a negative social welfare value as demonstrated by Bushnell and Stoft (1997).

Some of the criticisms of the FTR model are responded to by Hogan (2002a and 2003). The negative externalities can be taken care of by letting the investor pay for them as pointed out by Hogan (2002a). Moreover, Hogan agrees that the FTR market is only efficient when there is no market power, and when transmission investments are non-lumpy (or almost non-lumpy). He therefore indicates that merchant transmission investments should be for small-scale projects and that large and lumpy projects need regulation. Regulation is also necessary to prevent market power abuse. He argues that it is important to establish a boundary to differentiate between these investments.

Hogan (2003) also assumes that agency problems and information asymmetries are part of an institutional structure of the electricity industry where the ISO is separated from transmission ownership and where market players are decentralized.

However, he claims that the main issue on transmission investment is the decision of the boundary between merchant and regulated transmission expansion projects. He argues that asymmetric information should not necessarily affect such a boundary.

The main consensus in the FTR literature is the need for co-existence of central planning and merchant investment for the long-term FTR approach to work and create incentives for transmission expansion. Central planning is necessary because of economies of scale, free riding and incentives to congest the network. Joskow and Tirole (2002) argue that there must be a careful definition of the function of the ISO in planning, timing, and degree of participation in transmission expansion.

It is not clear if a central planned system could be combined with unplanned investments given their impact on the existing and future transmission system. The probabilities of all states of the world over the investment horizon must be considered. However, these probabilities are not of common knowledge and the actual probabilities chosen by the ISO could be subjective. Moreover, contingency markets are hard to implement in practice because they assume that the owners of the existing network are not neutral with respect to new investments. Hogan (2003) points out that contingencies in the short-run are taken into account by running security-constrained economic dispatch.

It is impossible to define the activity of the transmission system in terms of an output process, because it is impossible to physically trace electricity (Rosellon, 2003). An analytical determination of the cost and production functions could reveal if transmission has large sunk costs and sub-additivity. Under such an assumption the long-term behaviour of the Gridco could be regulated through some type of incentive regulation (Rosellon, 2003).

The main incentive for investing in transmission capacity is that the benefits from the transmission investment outweigh the benefits from congestion. A long-term FTR model would give efficient results under such a criterion. On the contrary, a transmission company that benefits more from congestion than expansion would have no incentives to expand the network.

Barmack et al. (2003) claim that FTRs alone will not induce efficient operation and investment as a part of the United States' standard market design. They argue that an optimal incentive mechanism should meet at least two criteria. First, it should encourage the transmission owner to equalize the marginal social benefit of reduced congestion costs and the marginal cost of reducing congestion (including the short and long-run). Second, it should not discriminate between capital and operational expenses as potential means of reducing congestion, but rather should encourage the transmission owner to pursue whichever approach is most cost-effective. They differentiate between congestion rents and congestion costs. Based on a comparison between congestion rent shortfalls (or surpluses) and redispatch costs they argue that the transmission owner is given incorrect incentives for efficient investment and operation. One of the criticisms is that investments eliminating congestion result in worthless FTRs. However, FTRs may be given to investors as a hedge against future price differences, not as a financing source. It is also difficult to make a correct allocation of FTRs. There is some amount of arbitrariness in the process of creating and allocating FTRs through the feasibility test. The model grid may be an inaccurate representation, resulting in over- or under-funding of payments to FTR holders. In the case of under-funding the transmission owner must make up the deficit and it will therefore have a risk by providing FTRs. Likewise, given the problems with allocating FTRs accurately, it may result in inefficient investments because investors are not allocated FTRs corresponding to the new capacity created. Barmack et al. (2003) also claim that the allocation of FTRs to investors in small-scale projects such as capacitors, transformers, or breakers will be imprecise and may not correspond to the new capacity created.

Barmack et al. argue that if the transmission owners should bear the risk of congestion rent shortfalls (from payments to FTR holders) they should be compensated by for example up-front payments to create funds that could be used to finance shortfalls. Alternatively, FTRs could be partially funded and pay only the congestion rents collected. Still another alternative is that independent transmission providers[50] (that are incorporating the assets of many different transmission owners) could issue FTRs in sufficiently restricted volumes so that shortfalls would be unlikely. As an alternative to FTRs they propose to use performance-based regulation.[51]

2.5.4 Pope and Harvey proposal for long-term financial transmission rights

Pope and Harvey (2002) present a methodology for implementing long-term FTRs. The ISO allocates long-term FTRs to parties that invest in transmission as long as these FTRs are made possible by the expansion. The incremental FTRs are allocated based on investor preferences, but the ISO could also allocate the FTRs.

In this process, the amount of existing and incremental FTRs must be taken into account such that all FTRs are simultaneously feasible and thus revenue adequacy is ensured. The auction including feasibility constraints checks that the investor's nominations are feasible and prevents the allocation of FTRs that were made infeasible by the expansion.

The bidding process is conducted over several steps. First, the investor can choose between short- and long-term FTRs[52] for transmission expansion. Second, the allocation of incremental FTRs takes place in an auctioned or un-auctioned period. In the auctioned period the FTR auction model allocates summer and winter incremental FTRs[53] based on investors' preferences. In order to make possible some transmission expansions, mitigating FTRs (that corresponds to counterflow FTRs) might be issued. In the un-auctioned period, transmission capacity is reserved to be released for sales in later periods. Finally, short-term FTRs are allocated through an auction.

[50] Independent transmission providers include regional transmission organizations and independent system operators.

[51] The basic structure of their proposal is that the transmission owner is allowed to collect a transmission fee based on the expected levels of demand, the revenue requirement of the grid, and redispatch costs.

[52] The long-term FTR typically is allocated at one-time with a life-time of 20 years, while the short-term FTR is allocated every 6 months with a life-time of 6 months.

[53] The separation between winter and summer FTRs is non-trivial because FTRs that are feasible in one period might be infeasible in another period.

Harvey (2002) analyzes the allocation of incremental FTRs associated with controllable DC lines. These lines require special attention in the transmission pricing, the feasibility test and how to allocate incremental FTRs. The allocation methodology depends on whether the expansion is done by a market player or by the ISO. When a market player schedules the line, the transmission pricing might differ from locational pricing when an outage of a DC line is a binding constraint. Conversely, when the ISO schedules the line, locational pricing would be prevailing.

2.5.5 Market power associated with transmission expansion

Léautier (2001) analyzes transmission expansion in a three-node network in a two period setting. Transmission expansion occurs in the first period resulting in revenues to the transmission owner. In the second period, the system operator maximizes consumer benefits in a dispatch allowing for loop flows and according to a pay-as-bid rule. Léautier finds two major effects. The first is a substitution effect where transmission expansion allows for substitution of cheaper electricity for more expensive electricity. The second is a strategic effect where competition in generation increases. The substitution effect always increases welfare, but the welfare impact of the strategic effect depends on the weight of generators' profits relative to consumers' utility weight. The higher the generators' weight, the lower the positive effect on welfare.

Based on these results Léautier argues that incumbent generators may not be the best market players to carry out transmission investments. Expansions allow generators to increase revenues by improved access to new markets, collecting transmission charges and FTR payments, but the benefits might be outweighed by loss of local market power. Therefore, generators might prefer to congest the network. To create welfare improving transmission investments the regulator must vertically separate the electricity industry, in order to make any market player able to invest in transmission.

Bushnell and Stoft (1997) show that in a three-node network, a generator might benefit from a social welfare reducing investment.

Based on the research findings in the literature, generators' behaviour in the FTR market should be regulated. Hogan (2002a) argues that transmission companies should be the principal buyers and sellers of long-term FTRs. Likewise, the Gridco could have the main responsibility of making a regulated investment under a market failure, but this would require strict imposition of open access to transmission networks.

2.5.6 Alternative approaches towards transmission expansion

Two other possible approaches towards transmission expansion besides the long-term FTR approach can be briefly mentioned. For a thorough overview, see Rosellon (2003).

The first of these defines the optimal expansion of the transmission network according to the strategic behaviour of generators, and considers conjectures made by each generator on other generators' marginal costs due to the expansion. The approach utilizes a real option analysis to evaluate the net present value of both transmission and generation investments and therefore their interdependences. The weakness is that it assumes a transportation model with no loop flows.

The second possible approach is given by regulatory mechanisms for Transcos. The basic principle is that the Transco faces the social costs of transmission congestion. One possibility is to use a two-part tariff cap that solves the opposite incentives to congest the existing transmission network and to expand it in the long-run. This approach utilizes the analysis of the cost and demand functions for transmission that still is in its infancy. For this approach to work there must be a monotonic increasing transmission cost function. Hogan (2002a) demonstrates that this assumption in general is not valid because an expansion of a certain link can lead to a decrease in total transmission capacity.

In the literature there is a debate regarding the use of a regulated Transco approach for transmission expansion. On the one hand, Hunt (2002) and Joskow and Tirole (2002) claim that a Transco model avoids the moral-hazard-in-teams problem of an ISO model. Therefore, the regulated Transco offers an advantage over the merchant FTR approach because the Transco carries out all externality calculations. In this sense, it would properly respond to incentive regulation even under loop flows (Vogelsang, 2001). On the other hand, the Transco approach faces implementation hurdles. As argued by Hogan (1999a), a Transco needs an institutional framework with a single grid owner. As explained by Wolfram (1999), the Transco system like the one currently used in the United Kingdom, relies on discriminatory treatment of transmission uses. This is unacceptable in other countries such as the United States. Finally, an incentive type of regulation can hardly be implemented in meshed networks because of the impossibility of correctly defining the output of the transmission system.

3 Summary of research findings and directions for further research

This thesis contains the eight research papers shown in Table 3-1. The main theme is transmission pricing and hedging of risks associated with transmission congestion. Both numerical tools and theoretical models have been utilized.

Table 3-1. Research papers included in the thesis.

Paper	Analysis	Model
"Transmission congestion risks"[54]	Theoretical analysis of different transmission risk management tools	Cash flow analysis and optimal hedge ratios
"Markets for financial transmission rights"[55]	Descriptive and empirical analysis of financial transmission rights in markets around the world	Market design and policy issues
"Utilizing MATPOWER in optimal power flow"[56]	Social welfare considerations	Application of numerical software to calculate locational prices
"Pricing of Contracts for Differences in the Nordic market"[57]	Empirical analysis of Contracts for Differences prices in the Nordic market	Spot-forward pricing and risk-premiums
"A merchant mechanism for electricity transmission expansion"[58]	Economic consequences of awarding long-term FTRs to investors in transmission expansion	FTR auction model
"Provision of financial transmission rights"[59]	Theoretical and numerical analysis of the credit risk of the ISO in providing FTRs	Maximum volume and value at risk calculations
"Effects of losses on area prices in the Norwegian electricity market"[60]	Impacts of losses and transmission congestion on locational prices after enforcing area pricing	Numerical software (MATPOWER)
"Financial risk management in the electric power industry"[61]	Analysis and discussion of numerical results obtained from a real case study on Norway's second largest hydropower generator	Stochastic optimization model developed by SINTEF Energy Research

[54] An early version of this paper was published in Kristiansen (2003a).
[55] Working paper.
[56] An early version of this paper was published in Modeling, Identification and Control (Kristiansen, 2003b).
[57] An early version of this paper will be published in Energy Policy (Kristiansen, 2004).
[58] An early version of this paper was published in Kristiansen and Rosellon (2003).
[59] An early version of this paper was published in Kristiansen (2003c).
[60] Submitted for publication (Kristiansen and Wangensteen, 2004).
[61] An early version of this paper was published in Kristiansen (2002).

3.1 Joint work with co-authors

The paper "A Merchant Mechanism for Electricity Transmission Expansion" was partly co-authored with Professor Juan Rosellon. I contributed with the realization of Hogan's proposal for merchant transmission investments in a modeling context, while Rosellon put the model in a regulatory economics context. We discussed the model solution and its impact on the electricity market in a way that was understandable by economists and policy makers. Later I included some more examples to the first version of our paper. I also co-authored the paper "Effect of Losses on Area Prices in the Norwegian Electricity Market" with my supervisor Professor Ivar Wangensteen. He had the hypothesis that losses would have an impact on the grouping of buses in an area price model. I implemented a model of a three-bus network in MATPOWER and modeled area prices and the impact of losses. We discussed the numerical results and policy implications together. The remaining papers are my own contributions.

3.2 Scientific contributions

This section summarizes the eight research papers and their findings.

Paper 1: Transmission congestion risks

The paper "Transmission congestion risks" analyzes contractual arrangements to manage spatial risk in electrical networks in the forward market, the bilateral market, and the Nordic market. The paper describes transmission risk management tools including time aspects.

Paper 2: Markets for financial transmission rights

The paper "Markets for financial transmission rights" presents a survey of markets for transmission rights around the world. It makes a comparison of the markets with regard to design and their associated advantages and disadvantages. It also describes efficiency in the FTRs markets and places FTRs in a policy context.

Paper 3: Utilization of MATPOWER in optimal power flow

The paper "Utilization of MATPOWER in optimal power flow" demonstrates how MATPOWER, a software simulation package, calculates the nodal prices as a result of an optimization of the minimum costs of active generation, taking into account the power system constraints. Strictly speaking, there are not any scientific contributions in this paper. However, the emphasis is on the utilization of MATPOWER as a tool for calculating locational prices and description of the software that is used in paper 7.

Paper 4: Pricing of Contracts for Differences in the Nordic market

The paper "Pricing of Contracts for Differences in the Nordic market" analyzes the CfD prices for the first eight trading periods. Based on a comparison between the trading prices of the contracts and the average of the seasonal area price minus the System Price during the settlement period, they appear to be over-priced on average ex post. The explanation may be the presence of a majority of risk-averse consumers who are willing to pay a risk premium for receiving the future price differential.

The findings included the fact that contracts were under-priced ex post. The prices of the contracts depend on the inflow in the actual year which is an important factor in creating transmission congestion. Since every contract is referred to a season or a year, this makes the present amount of data limited. To my knowledge, this is the first survey of how CfDs have been priced.

Paper 5: A merchant mechanism for transmission expansion

The paper "A merchant mechanism for transmission expansion" proposes a merchant mechanism to invest in electricity transmission. Proxy awards (or reserved FTRs) are a fundamental part of this mechanism. We defined them according to the best use of the current network along the same direction of the incremental expansion. The incremental FTR awards are allocated according to the investor preferences, and depend on the initial partial allocation of FTRs and network topology before and after expansion.

Our examples showed that the internalization of possible negative externalities caused by potential expansion is possible according to the rule proposed by Hogan (2002a): allocation of FTRs before (proxy FTRs) and after (incremental FTRs) the expansion is in the same direction and according to the feasibility rule. Under these circumstances, the investor will have the proper incentives to invest in transmission expansion in its preference direction given by its bid parameters. Likewise, the larger the existing current capacity the greater the number of FTRs that must be reserved in order to deal with potential negative externalities depending on post network topology.

Our mechanism of long-term FTRs is basically a way to hedge market players from long-run nodal price fluctuations by providing them with the necessary property transmission rights. Although our model is specifically designed to deal with loop flows, and the security-constrained version of our model can take care of contingency concerns, our proposed mechanism is to be applied to expansions where the locational price difference does not vanish totally. Long-term FTRs are efficient under no or small returns-to-scale marginal expansions of the transmission network, and lack of market power. Regulation has then an important complementary role in fostering large and lumpy projects where investment is large relative to market size, and in mitigating market power. Since revenues from nodal prices only recover a small part of total costs, long-term FTRs must be complemented with a regulated framework that allows the recovery of fixed costs. The challenge is to effectively combine merchant and regulated transmission investments or, as Hogan (2003) puts it, to establish a rule in practice for drawing a line between merchant and regulated investments.

Paper 6: Provision of financial transmission rights

The paper "Provision of financial transmission rights" demonstrates the key issues associated with the provision of FTR obligations and options. In particular, the independent system operator (ISO) must conduct an analysis of revenue adequacy, because the maximum volume of FTRs (both obligations and options) will vary with the transmission line capacities and contingencies. In a three-bus network, the maximum volume associated with an issue of a single FTR is determined by the shift factor matrix elements and transmission line capacities. The paper shows the alternative relationship for the maximum volume, congestion rent and locational prices. Due to counterflows a higher volume of FTRs might be issued between certain buses. Conversely, a lower volume of options than obligations must be issued because they do not create counterflows. Proceeds from the FTR auction were considered and demonstrated that a higher volume might be issued. Uncertainty associated with congestion gave the ISO an uncertain cash flow, composed of the congestion rent and payments to the FTR holders. As a tool for risk management any provider could utilize the VaR approach. The VaR shows that the greatest potential loss occurs when FTRs with the highest expected payments are issued and the lowest when FTRs with the lowest expected payments are issued. Private parties would not have to fulfill the simultaneous feasibility test and might buy insurance in the market to hedge any risks associated with providing FTRs.

Paper 7: Effect of losses on area prices in the Norwegian electricity market

The paper "Effect of losses on area prices in the Norwegian electricity market" demonstrates that taking into account the joint interaction of losses and transmission congestion may have significant impacts on the individual bus prices. The numerical results illustrate that the bus prices differ due to both transmission congestion and losses when there is a transmission constraint binding in the full transmission network. Moreover, running a DC and an AC OPF may have different impacts on the bus prices. We also illustrate and describe the current practice for area pricing in Norway. Numerical results illustrate that area prices may change substantially after regrouping the buses in different price areas or when using a DC OPF rather than an AC OPF.

Paper 8: Financial risk management in the electric power industry

The paper "Financial risk management in the electric power industry" demonstrates that it is possible to apply an integrated risk management model to realistic cases. The case results show that hydropower generation and trading in the futures market change with the risk aversion. In general it was found that the expected income decreased with increasing penalty as expected. The minimum income scenarios in the closest income periods are reduced when risk aversion is introduced. When no hedging in the futures market is allowed, the water is moved between the different time periods (seasons) to meet the income targets.

The model gives risk adjusted water values as output and these can be used as a condition for sale in the spot market. Likewise, marginal contract values, when properly adjusted, can be used as signals for buying or selling in the futures market.

When dynamic hedging is introduced, the simulated income uncertainty is reduced and the model offers a more realistic forecast of the associated income for a portfolio of physical generation, futures contracts, and load factors contracts. An optimization of both physical generation and the contract portfolio is necessary because the information about reservoir levels and rest volumes gives signals for changes in future position and reduces inflow risks.

3.3 Directions for further research

The study of transmission congestion derivatives prices will be improved with more empirical data as time passes and therefore needs to be updated periodically. Likewise, the PJM market, the New England market, and other markets that have implemented FTRs could be analyzed.

The main purpose of the four basic axioms that support the long-term financial transmission rights model (*feasibility rule*, *proxy awards*, *maximum value* and *symmetry*) were to define property rights for increased transmission investment according to the preset proxy rule. However, the general implications on welfare and incentives for gaming are still an open research question. Another “axiom” might be needed to deal with these last issues.

4 Transmission congestion risks

In this chapter we describe available instruments for hedging against transmission congestion risks. These include forward contracts and options. We illustrate risk management strategies for trades between two locations when transmission congestion is present. Risk management in three different markets is exemplified by the general forward market, the bilateral market, and the Nordic market. Cash flow analysis describes the conditions under which hedging is profitable and demonstrates that players can protect themselves against future price differences. Taking into account that a riskless hedge may be non-optimal if the objective is to minimize variance, the optimal hedge ratio for forward contracts is calculated.

4.1 Introduction

After deregulation of electricity markets, price volatility has increased. Therefore, hedging instruments play an important role in the most well-functioning markets (e.g. Nord Pool). Trading across different regions creates risks that can be managed by use of financial transmission rights (Hogan, 1992) and energy forward contracts (Rajaraman and Alvarado, 1998).

When market players trade between different locations, they face the risk of paying a congestion fee for transferring electricity. The congestion fee from bus i to bus j is defined as:

$$\text{Congestion fee} = O_{ij}\,(P_j - P_i) \tag{4.1}$$

where O_{ij} is the amount of transferred electricity from bus i to bus j and P is the local bus[62] price. The congestion fee arises from the scarcity of transmission.[63] It is typically zero because there is adequate transmission capacity most of the time. When transmission capacity is scarce, however, prices can become high. To some extent these prices are predictable, but they contain a significant random component that can be problematic for traders.

If a generator trades with load at the local bus, it is not charged for transmission, and can use a forward product to hedge the price uncertainty. If a generator trades with a distant load, and there is a chance of congestion, the trade is exposed to transmission price risk. This discourages trade because trading across a congested path in either direction will be risky (Stoft, 2002). This may enhance market power by decreasing the number of distant trades. To reduce such problems players can utilize financial instruments to hedge against transmission congestion.

[62] A bus refers to a node in the transmission network.

[63] This ignores the charge for losses, which is almost never above 10% and is far more predictable.

4.2 Financial transmission rights

The basic types of transmission rights are:

- Financial transmission rights (FTRs[64]) obligation: right to collect payment from (or an obligation to pay) the price difference associated with transmission congestion between destination and origin for a specified contract quantity.[65]
- Financial transmission rights (FTRs) option: right to collect payment from the price difference associated with transmission congestion between destination and origin for a specified contract quantity. If the price difference is negative the payoff is zero.
- Flowgate rights (FGRs[66]): constraint-by-constraint hedge that gives the right to collect payments based on the shadow price associated with a particular transmission constraint.
- Physical transmission rights (PTRs): right or priority to physical transmission for a specified amount between two defined locations.

While forward contracts are used to hedge the temporal risk, transmission rights are used for hedging spatial risk.[67] Transmission rights are used mainly to facilitate trade in advance of the physical scheduling (usually done by a system operator a day in advance). Physical and financial transmission rights have different impacts on market power and on the electricity transmission system. Every transmission line at any time has a net directed power flow, which may consist of flows in both directions (both are fictitious). For FTRs only the net power flow matters, while for physical rights the directed power flow determines their feasibility.

Financial rights are only instruments for hedging against financial risk. Often they are provided by the ISO and are restricted in number by the network capacity calculations of the ISO that ensures that the independent system operator (ISO) has sufficient revenues to cover the payments to FTR holders (Hogan, 1992). Provision of options is more restrictive because they do not create counterflows. The feasibility test can be complex and may require a central coordinator to produce a feasible set of FTRs.

Physical rights give the right to inject a certain amount of electricity at point *i* and withdraw it at point *j*. The holders are guaranteed scheduling for their rights. These rights can make withholding of transmission capacity possible and necessitate capacity release rules (use-it-or-lose-it principle), and are more restrictive than FTRs. Another type of physical right confers only a scheduling priority and is a less centralized and more flexible approach.[68]

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[64] FTRs are also often called transmission congestion contracts (TCCs). For more background on FTRs see Hogan (2003) and Stoft (2002).

[65] The set of point-to-point obligations can be decomposed into a set of balanced and unbalanced (injection or withdrawal of energy) obligations. The unbalanced FTRs can be used to hedge against losses (Hogan, 2002b).

[66] In the earliest proposals, these rights were categorized as physical rights, but in the recent proposals the value of the FGRs are decided in the ISO settlements, and they do not require the parties to obtain all the FGRs needed prior to settlement.

[67] FTRs are usually also forward contracts, since they are hedges against future transmission prices.

[68] An example is firm transmission rights in California.

An FTR obligation will entitle its owner to be paid the price difference between two buses times the contract quantity over a specified time period. This payment will net out any price risk associated with using that path (i.e. paying congestion fees) if the hedge is perfect. Such payments will be made regardless of the owner's actual usage of the transmission system. The payments under this right are therefore independent of the owner's physical use of the grid. Even if the congestion risk is hedged, traders will still be exposed to locational price signals and should still make efficient choices for generation and load. The mathematical formulation for the payoff is:

$$\text{FTR} = Q_{ij}(P_j - P_i) \tag{4.2}$$

where P_j is the bus price at location j, P_i is the bus price at location i and Q_{ij} is the directed quantity specified for the path from i to j. An FTR obligation may be viewed as an injection Q_{ij} of electricity at bus i and a withdrawal of Q_{ij} at bus j. A perfect hedge is created by purchasing a contract quantity, Q, that equals the amount of electricity that is transferred between the two locations, O. An FTR may be acquired by either purchasing it in auctions or in the secondary markets, or by investing in transmission lines. Ideally, the auction price of an FTR obligation should equal the expected future congestion price.

Locational prices are needed before an FTR can be defined. These should depend on transmission congestion and perhaps losses. Typically, FTR obligations are forward contracts that are settled in the day-ahead market. Their payoff (assuming a fixed contract quantity) is only dependent on the bus prices, not on the actual power flow, and it may be positive, zero or negative as illustrated in Figure 4-1 for a 1 MW FTR obligation. Prices will change during the specified contract period, so the value of the total payment to the FTR holder is calculated by averaging a series of fluctuating locational prices.

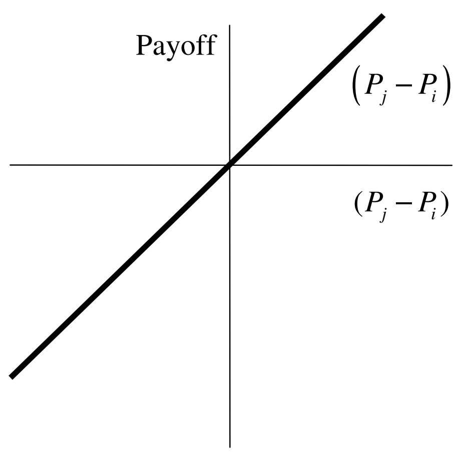

Figure 4-1. Payoff from a 1 MW FTR obligation.

An FTR obligation will have a negative value if the contract covers a path for which the price at bus i (injection) is higher than the price at bus j (withdrawal), $P_i > P_j$. This can happen because the acquired FTR is defined opposite to the prevailing direction, or because electricity on this path is flowing from a high to a low price bus. The first is highly desirable in a transmission system because it relieves congestion, while the second can exist in a meshed network. In either case, if the FTR of the trader more than covers its transmission needs during slack periods, the trader may suffer an unpredictable financial penalty for owning the unused part of its right (Bushnell and Stoft, 1996).

A point-to-point transaction can also be hedged by purchasing a mix of other FTRs. However, locational prices, congestion fees, and the values of FTRs are undefined until the dispatch occurs. Thus, the trader cannot be certain whether any mix of FTRs other than the point-to-point FTR provides a perfect hedge. FTRs may be more flexible if they are defined to and from central hubs because the buyer and seller then have one FTR for the same hub. When the buyer and seller enter into a contract they use two FTRs to hedge the congestion fee. The holders can then freely trade their contracts and make the secondary market more liquid. In general FTRs are more difficult to trade because of the large number of possible buses they can be defined between. In an N-node network the possible number of FTRs is $1/2 \cdot N(N+1)$ for $N>2$. An FTR obligation is decomposable and has the following properties:

$$(P_j - P_j) = (P_{hub} - P_i) + (P_j - P_{hub}) \tag{4.3}$$
$$(P_j - P_i) = -(P_i - P_j)$$

FTRs can also be purchased as one-way options. In this case the holder is not responsible for negative payments that occur when the locational price difference is negative. The mathematical formulation for the payoff is:

$$\text{FTR\_option} = \max\,(Q_{ij}\,(P_j - P_i),\, 0) \tag{4.4}$$

Payments from an option are non-negative, and the option will have a clearing price greater than or equal to the price of an FTR obligation. The clearing price of an option is a function of the shadow price of each binding transmission constraint and it will never be less than zero for a buy bid. The payoff from a 1 MW FTR option is illustrated in Figure 4-2. A physical transmission right has a similar payoff.

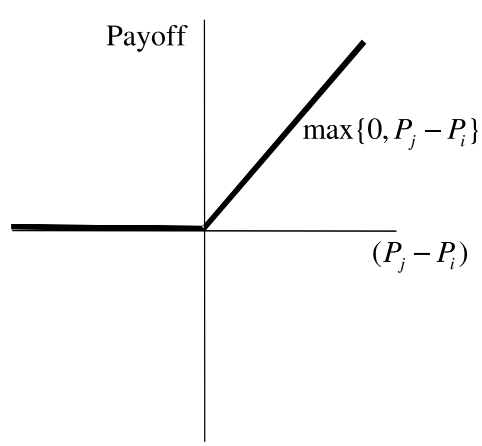

Figure 4-2. The payoff from a 1 MW FTR option.

If the objective is to fully and efficiently utilize the network, schedules that create counterflows are necessary, because they relieve congestion. Obligations also provide parties with transaction hedges against price uncertainty at generation and load buses. They work in favor of obligations. In the presence of counterflows, options issued by the ISO will not allow full hedging. The parties can then try to work out hedging arrangements in the private market. The FTR option does not have the same decomposition properties as the FTR obligation as demonstrated by:

$$\begin{aligned}&\max(0, P_j - P_i) \neq \max(0, P_{hub} - P_i) + \max(0, P_j - P_{hub})\\&\max(0, P_j - P_i) \neq -\max(0, P_i - P_j)\end{aligned} \tag{4.5}$$

Still another alternative is to use flowgate rights (Chao and Peck, 1996 and 1997). The idea is that since electricity flows along many parallel paths, it may be natural to associate the payments with the actual electricity flows. Key assumptions include a power system with few flowgates or constraints, known capacity limits at the flowgates and known power transfer distribution factors (PTDFs) that decompose a transaction into the flows over the flowgates. In practice, however, this may not be the case. The physical rights approach has been abandoned and a financial approach has been proposed in the literature (Hogan, 2002b). The payoff from the FGRs is determined by taking the associated flowgate shadow price times the flowgate amount and totaling them for all lines k that are affected by the transaction between buses m and n (Equation (2.25)).

$$\begin{aligned}&\text{FGR} = \sum_k \eta_k f_k^f\\&\eta_k = \text{shadow price}\\&f_k^f = \left(\nabla K_y(Y^*, u^*)\right)_{kmn} Q_k = \text{the flowgate amount}\\&\left(\nabla K_y(Y^*, u^*)\right)_{kmn} = \text{ the PTDF at the optimal operating point } (Y^*, u^*)\\&\text{for a transaction between buses } m \text{ and } n \text{ over line } k\\&Q_k = \text{contract quantity}\end{aligned} \tag{4.6}$$

The flowgate amount can take negative, zero or positive values.

To illustrate how FGRs can be used for hedging an example is provided in Figure 4-3 (Singh, 2003). Here a 100 MW transaction from A to E would pay:

$$\eta_{\text{BE}} \cdot 60 + \eta_{\text{CD}} \cdot 20 = \$1000$$

Thus the transaction can be hedged by buying 60 MWs FGRs on BE and 20 MW FGRs on CD. However, important issues are what happen if for example line AB becomes congested or if the PTDFs change. A perfect hedge for the same transaction could be accomplished by purchasing a 100 MW FTR between A and E that would pay exactly the same and would remain perfect if other lines became congested or the PTDFs changed.

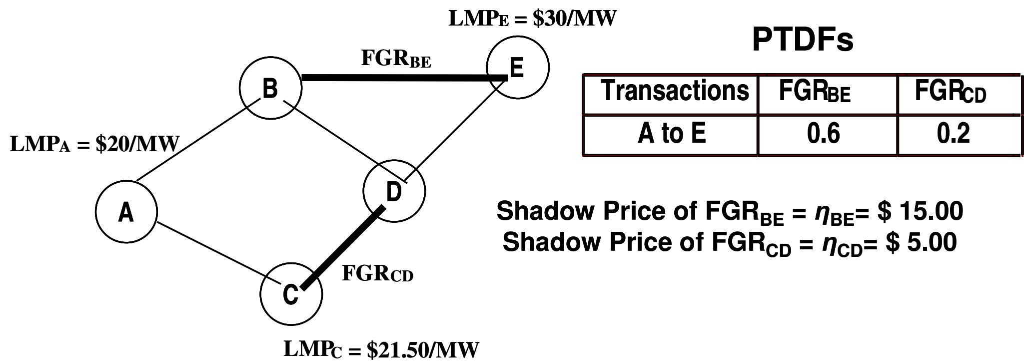

Figure 4-3. Flowgate right example (Singh, 2003).

In general, parties that want to be fully hedged should purchase a mix of FGRs that matches the distribution of flows from its transaction.[69] In a transmission network, the flows will be determined by the line impedances, and more than one flowgate (transmission constraint) may be affected. Flowgate proponents assert that trading is easy if there are few commercially significant flowgates, resulting in a limited set of FGRs and if the PTDFs change infrequently (Chao et al. 2000). This seems difficult to ensure in a dynamic power system where unanticipated transmission constraints may become binding (Hogan, 2000).

Although some ISOs sell transmission rights in their day-ahead markets, these markets are only approximations of the real-time congestion prices. A continuous market with a slowly changing price that traders can observe before trading may be needed. Afterwards, they can purchase transmission rights at a price close to the observed transmission price. As yet, there are no such markets.

4.3 Contracts for Differences

The Nordic market (i.e. Nord Pool) has introduced Contracts for Differences (CfDs).[70] These financial instruments make it possible for the market players to hedge against the difference between the area (zonal) price and the System Price (the unconstrained price) in a future time period (Nord Pool, 2002c). The area prices that are traded are: Oslo (NO1), Stockholm (SE), Helsinki (FI), Århus (DK1), and Copenhagen (DK2).

[69] This assumes that all constraints that could have been binding in the dispatch have been designated as flowgates, and that the ISO has made FGRs available for all flowgates. If some constraints have not been designated, but become binding, then there is no mechanism by which parties can purchase a perfect hedge. Some proposals for FGRs take this into account by not charging holders for the non-predicted constraints and instead socialize the costs.

[70] Here, the term Contract for Differences is different from the corresponding term used in the British market. In the Nordic region, CfDs are used to hedge against the difference between the two uncertain prices (area price and System Price), not as in the British market, where they hedge the difference between the spot price and a pre-defined reference price or price profile. The Nordic CfD is a locational swap, while the British CfD is settled based on the difference between the spot price and the reference price. When referring to CfD in the Nordic market, the term Nordic CfD is used.

The forward and futures contracts traded at Nord Pool are with reference to the System Price. Producers are paid the area price for generation in their area. Consumers purchase electricity at their respective area price. Often, producers and consumers in different areas encounter situations of transmission congestion when the area prices differ from the System Price. They may also be exposed to significant financial risks associated with congestion fees for bilateral transactions in the Nordic countries that are calculated based on the difference between the area prices times the transferred quantity. Usually producers pay the fee, but parties can also make other arrangements.

The payment from the Nordic CfD is:

$$\text{CfD} = Q_i\,(AP_i - SP) \tag{4.7}$$

where AP_i refers to the area price in area *i, SP* is the System Price, and Q_i is the contracted volume. Payments are calculated as the average of the difference between the daily area price and the System Price during the delivery period (a season or a year) times the contracted volume. From Equation (4.7) we see that each time the area price is higher than the System Price the holder receives a payment equal to the price differential times the contracted volume. Otherwise the holder must pay the difference.

The market price of a Nordic CfD can be positive, negative or zero (Kristiansen, 2004). CfDs trade at positive prices if the market expects that the area price will be higher than the System Price (a net import situation). CfDs trade at negative prices if the market expects an area price below the System Price (a net export situation).

A perfect hedge using forward or futures contracts is possible only when the area price and the System Price are equal. If forward or futures contracts are used for hedging, this implies a basis risk equal to the area price minus the System Price. To create a perfect hedge against the price differential:

4. Hedge the specified volume by using forward contracts.
5. Hedge against the price differential – for the same period and volume – by using CfDs.
6. Accomplish physical procurement by trading in the Elspot area of the holder of the contract.

Norway has adopted an area (zonal) price model to manage congestion in the day-ahead market. A charge equal to the difference between the System Price and low area price times the transferred quantity (capacity charge) is imposed in the low price area, and a charge equal to the difference between the high area price and the System Price times the transferred quantity is imposed in the high price area. Thus, withdrawals are charged in the high price area and compensated in the low price area. The opposite is the case for injections. However, it is impossible to hedge against price differences within Norway, because there is only one contract with reference to the area Norway 1 (Oslo). Shorter-term products and products for hedging directly against area price differentials are unavailable at the exchange. Nord Pool is considering listing CfDs with reference to Norway 2 (Trondheim) and CfDs with shorter delivery periods such as weeks or months (Nord Pool, 2003). Nord Pool is also considering the listing of CfDs with reference to the German EEX price.

4.4 Transmission risk management contractual arrangements

We analyze three different markets: a forward market (including a day-ahead market), a bilateral market, and the Nordic market. There are no deviations in the real-time market from the contracted volume. Hence, the market player does not participate in the real-time market and is paid the day-ahead price.

4.4.1 Forward market

Assume that the generator sells electricity to a load at bus 2. The generator is paid the price at bus 2 and pays a congestion fee to the system operator so that the price it is effectively paid equals the price at bus 1. The load pays the price at bus 2. Other arrangements are also possible depending on the contract type. Assume that bus 1 is a surplus area and bus 2 is a deficit area. The price at bus 1 is therefore expected to be lower than at bus 2.

Table 4-1. Consequences for the generator facing a congestion fee in the day-ahead market without an FTR.

	Day-ahead market	Congestion fee	Total cash flow
Generator is paid:	$Q_{12}P_2$	$-Q_{12}(P_2 - P_1)$	$Q_{12}P_1$
Load pays:	$Q_{12}P_2$		$Q_{12}P_2$

The cash flow analysis shows the generator is indifferent between selling electricity at its local bus and at bus 2 (Table 4-1). To hedge the congestion fee, the generator buys an FTR obligation for the contracted volume. Its cash flow is shown in Table 4-2, where p_{FTR} is the contract price of the FTR.

Table 4-2. Consequences for the generator facing a congestion fee in the day-ahead market with an FTR.

	Day-ahead market	Congestion fee	FTR	Total cash flow
Generator is paid:	$Q_{12}P_2$	$-Q_{12}(P_2 - P_1)$	$Q_{12}(P_2 - P_1)$ $-Q_{12}p_{FTR}$	$Q_{12}P_2 - Q_{12}p_{FTR}$
Load pays:	$Q_{12}P_2$			$Q_{12}P_2$

The revenue of the generator will be dependent on the price at bus 2 and the price of the FTR. It avoids paying a congestion fee and is paid the price at bus 2 by purchasing an FTR. This arrangement is profitable if the contract price is less than the differences in the local day-ahead prices, $p_{FTR} < P_2 - P_1$.

Table 4-3. Consequences for the generator arranging a sale in the low price area (bus 2) in the day-ahead market without an FTR.

	Day-ahead market	Congestion fee	Total cash flow
Generator is paid:	$Q_{12}P_2$	$Q_{12}(P_1 - P_2)$	$Q_{12}P_1$
Load pays:	$Q_{12}P_2$		$Q_{12}P_2$

If the price at bus 1 is higher than at bus 2 and the generator has arranged a sale at bus 2, the generator receives compensation for relieving congestion equal to the congestion fee as shown in Table 4-3. Therefore it is indifferent to selling electricity at the local (high price) bus and the distant (low price) bus.

Table 4-4 illustrates the situation in which the generator receives compensation, but the FTR is an obligation so the generator must pay the same amount to the seller of the right. Buying an FTR is profitable if the contract price is less than the difference in prices between locations 2 and 1.

Table 4-4. Consequences for the generator arranging a sale in the low price area in the day-ahead market with an FTR.

	Day-ahead market	Congestion fee	FTR	Total cash flow
Generator is paid:	$Q_{12}P_2$	$Q_{12}(P_1 - P_2)$	$-Q_{12}(P_1 - P_2)$ $-Q_{12}p_{FTR}$	$Q_{12}P_2 - Q_{12}p_{FTR}$
Load pays:	$Q_{12}P_2$			$Q_{12}P_2$

Next, assume that a trader arranges to buy Q_{12} at a price P_1 from the generator at bus 1 (low price) and sell it to the load at bus 2 for the price P_2 (high price). It also pays the congestion fee as shown in Table 4-5.

Table 4-5. Consequences for the trader in the day-ahead market without an FTR.

	Day-ahead market	Congestion fee	Total cash flow
Generator is paid:	$Q_{12}P_1$		$Q_{12}P_1$
Load pays:	$Q_{12}P_2$		$Q_{12}P_2$
Profit of the trader:	$Q_{12}(P_2 - P_1)$	$-Q_{12}(P_2 - P_1)$	0

The trader does not profit when the line is congested. To hedge the congestion fee, it buys an FTR and receives a profit (or an expense) equal to that of the congestion fee minus the contract cost. If the price of the FTR is lower than the price differential between buses 2 and 1, this is a profitable trade as shown in Table 4-6.

Table 4-6. Consequences for the trader in the day-ahead market with an FTR.

	Day-ahead market	Congestion fee	FTR	Total cash flow
Generator is paid:	$Q_{12}P_1$			$Q_{12}P_1$
Load pays:	$Q_{12}P_2$			$Q_{12}P_2$
Profit of the trader:	$Q_{12}(P_2 - P_1)$	$-Q_{12}(P_2 - P_1)$	$Q_{12}(P_2 - P_1)$ $-Q_{12}p_{FTR}$	$Q_{12}(P_2 - P_1)$ $-Q_{12}p_{FTR}$

4.4.2 Hedging by taking opposite positions in the forward markets

This hedging strategy requires that there are two energy forward markets with prices p_1 and p_2 in the two regions in which the trade Q_{12} is accomplished. The hedge gives the same payoff as the congestion fee, $Q_{12}(P_2 - P_1)$. Assume that the contracted volume is Q_{12}. The generator in region 1 can then enter into a contract agreement where it is long (buying) in the region of the load and short (selling) in its own region. The congestion fee is paid by the generator. This gives a combined cost equal to:

$$Q_{12}(p_2 - p_1) + Q_{12}(P_2 - P_1) - Q_{12}(P_2 - P_1) = Q_{12}(p_2 - p_1) \tag{4.8}$$

where p_1 and p_2 are the forward prices in the two regions. Parties have also agreed that the generator sells electricity to the load at price p_C. The consequences are illustrated in Table 4-7.

Table 4-7. The cash flows of a generator from a bilateral trade while hedging against the congestion fee.

	Forward market	Congestion fee	Day-ahead market	Total cash flow
Generator is paid:	$Q_{12}p_1 - Q_{12}p_2$ $+Q_{12}\,p_C$	$-Q_{12}(P_2 - P_1)$	$Q_{12}(P_2 - P_1)$	$Q_{12}p_1 - Q_{12}p_2$ $+Q_{12}\,p_C$

This contractual arrangement gives the generator a cash flow that is perfectly hedged. When there is congestion ($P_2 > P_1$) the generator in region 1 will receive a net profit which may be higher than in its local forward market,[71] since it can sell electricity in region 2 at the fixed price p_C at a cost of $Q_{12}(p_2 - p_1)$.

4.4.3 Hedging with options

The advantage of an option is that it does not give a negative payoff. However, the price will be higher, since the market prices this into a premium. The payoff from the option is:

[71] This depends on the level of the forward prices in region 2 compared to the fixed contract price p_C. If the contract price is higher than the forward price in region 2, the net profit will be higher. Conversely, when the contract price is lower than the forward price in region 2, the net profit will be lower.

$$Q_{12}\max(0, P_2 - P_1) = \begin{cases} Q_{12}(P_2 - P_1) & P_2 > P_1 \\ 0 & P_1 > P_2 \end{cases} \tag{4.9}$$

When the price at bus 2 is higher than at bus 1, the generator is assumed to pay the congestion fee.

Table 4-8. Consequences for the generator facing a congestion fee in the day-ahead market when buying an option.

	Day-ahead market	Congestion fee	Option	Total cash flow
Generator is paid:	$Q_{12}P_2$	$-Q_{12}(P_2 - P_1)$	$Q_{12}(P_2 - P_1)$ $-Q_{12}p_{option}$	$Q_{12}P_2 - Q_{12}p_{option}$
Load pays:	$Q_{12}P_2$			$Q_{12}P_2$

The generator has hedged the congestion fee as shown in Table 4-8. Its expected profit will be lower than by purchasing FTRs because the price of the option will be correspondingly higher. Consider the case where the price at bus 1 is higher than at bus 2 and the sale is conducted at bus 2 (Table 4-9). The generator receives its price at bus 1 because it receives a rebate equal to the congestion fee for relieving congestion, but at the same time it has paid for an option with zero payoff ($P_1 > P_2$).

Table 4-9. Consequences for the generator facing a congestion fee in the day-ahead market when buying an option and the price at bus 1 is higher than at bus 2.

	Day-ahead market	Congestion fee	Option	Total cash flow
Generator is paid:	$Q_{12}P_2$	$-Q_{12}(P_2 - P_1)$	$-Q_{12}p_{option}$	$Q_{12}P_1 - Q_{12}p_{option}$

4.4.4 The bilateral market

Traders must find each other and negotiate contracts. Consider two types of contracts: a standard bilateral contract and a British contract for differences (CfD). The British CfD makes it possible to hedge against the difference between the spot[72] price and a pre-defined reference price or price profile and can be written in several ways.

Assume that the generator and load have signed a bilateral contract of volume Q_{12} without the benefit of a middleman. The price of the contract is P_C. The generator pays the congestion fee and is paid the contract price. P_1 is the day-ahead price at the bus of the generator. P_2 is the day-ahead price at the bus of the load. First consider the case with the bilateral contract and no insurance as shown in Table 4-10.

[72] The spot price is assumed to be equal to the day-ahead price, since there are no deviations in contracted and delivered volumes. Originally the CfD was with reference to the spot price.

Table 4-10. Consequences for the generator paying a congestion fee in the bilateral market without an FTR.

	Bilateral market	Congestion fee	Total cash flow
Generator is paid:	$Q_{12}P_C$	$-Q_{12}(P_2 - P_1)$	$Q_{12}P_C - Q_{12}(P_2 - P_1)$
Load pays:	$Q_{12}P_C$		$Q_{12}P_C$

By buying an FTR the generator will be compensated for the congestion fee as shown in Table 4-11. The FTR makes it possible to fix the price of transmission. The arrangement will be profitable if $p_{FTR} < P_2 - P_1$ which is the same condition as in the preceding cases.

Table 4-11. Consequences for the generator with an FTR.

	Bilateral market	Congestion fee	FTR	Total cash flow
Generator is paid:	$Q_{12}P_C$	$-Q_{12}(P_2 - P_1)$	$Q_{12}(P_2 - P_1)$ $-Q_{12}p_{FTR}$	$Q_{12}P_C - Q_{12}p_{FTR}$
Load pays:	$Q_{12}P_C$			$Q_{12}P_C$

The second example considers a CfD where the generator pays for transmission. The situation is illustrated in Table 4-12.

Table 4-12. Generator pays for transmission CfD.

Effect of CfD	Payment from load to generator
Generator pays for transmission:	$Q_{12}(P_C - P_2)$

The generator is not hedged against locational price differences as illustrated in Table 4-13. The effect of using the CfD is that the load pays a fixed price for the electricity, while the generator receives a fixed price for electricity and pays the congestion fee. To hedge the congestion fee, the generator can buy an FTR as shown in Table 4-14.

Table 4-13. Cash flows to the parties resulting from using a CfD when the generator pays for transmission.

	CfD	Spot market	Total cash flow
Generator is paid:	$Q_{12}(P_C - P_2)$	$Q_{12}P_1$	$Q_{12}P_C - Q_{12}(P_2 - P_1)$
Load pays:	$Q_{12}(P_C - P_2)$	$Q_{12}P_2$	$Q_{12}P_C$

Table 4-14. Cash flows to the parties resulting from using a CfD when the generator pays for transmission and has purchased an FTR.

	CfD	Spot market	FTR	Total cash flow
Generator is paid:	$Q_{12}(P_C - P_2)$	$Q_{12}P_1$	$Q_{12}(P_2 - P_1)$ $-Q_{12}p_{FTR}$	$Q_{12}P_C - Q_{12}p_{FTR}$
Load pays:	$Q_{12}(P_C - P_2)$	$Q_{12}P_2$		$Q_{12}P_C$

In the next example, the trader pays the congestion fee, because it has agreed to buy Q_{12} at bus 1 at a price f_1 and sell the power at bus 2 at a price f_2. However, since both the generator and load participate in the spot market, the trader must specify that the generator will pay it $Q_{12}P_1$ (the amount the generator is paid in the local spot market). The trader pays load $Q_{12}P_2$ (the amount the load pays in the local spot market). This trade constitutes two CfDs: trader pays generator $Q_{12}(f_1 - P_1)$ and load pays the trader $Q_{12}(f_2 - P_2)$. This arrangement is favorable when the generator and load want price certainty, and the trader wants to exploit profits from electricity trading. The trade is illustrated in Table 4-15.

Table 4-15. Cash flows to a trader providing two CfDs and at the same time paying the congestion fee.

	CfD	Spot market	Congestion fee/FTR	Total cash flow
Generator is paid:	$Q_{12}(f_1 - P_1)$	$Q_{12}P_1$		$Q_{12}f_1$
Load pays:	$Q_{12}(f_2 - P_2)$	$Q_{12}P_2$		$Q_{12}f_2$
The profit of the trader:	$Q_{12}(f_2 - f_1)$		$-Q_{12}(P_2 - P_1)$	$Q_{12}(f_2 - f_1)$ $-Q_{12}(P_2 - P_1)$
The profit of the trader with an FTR:	$Q_{12}(f_2 - f_1)$		$-Q_{12}(P_2 - P_1)$ $+Q_{12}(P_2 - P_1)$ $-Q_{12}p_{FTR}$	$Q_{12}(f_2 - f_1)$ $-Q_{12}p_{FTR}$

As shown the trader is perfectly hedged against locational price differences by purchasing an FTR. This is profitable for the trader as long as the contract price is less than the difference in bus prices between the two locations.

4.4.5 The Nordic market

Assume that there is a System Price (i.e. unconstrained price), and area (zonal) prices. Most financial contracts are referred to the System Price, while the generators are paid the local price for their production and the consumers pay their local area price. This means that the parties are left with a risk that the System Price and the local area price differ due to transmission congestion. According to the area price model, withdrawals are charged in the high price area and compensated in the low price area. Injections are compensated in the high price area (*B*) and charged in the low price area (*A*). Congestion fees for bilateral transactions in the Nordic countries are calculated based on the difference between the area prices times the transferred quantity.

Assume a load has purchased a forward contract of volume Q_s from the exchange at the price p_f and a CfD of the same volume at the price p_{CfD}. In addition, it also accomplishes physical procurement by trading the same volume in its local spot area. The cash flow during the delivery period is shown in Table 4-16.

Table 4-16. The cash flows of a load in the delivery period resulting from the purchase of a forward and a Nordic CfD.

	Forward market	CfD	Day-ahead market	Total cash flow
Load pays:	$Q_s\, p_f$	$Q_s\, p_{CfD}$	$Q_s\, AP_B - Q_s\, SP$ $-Q_s(AP_B - SP)$	$Q_s(p_f + p_{CfD})$

The load fixes the costs of purchasing electricity to the prices of the forward contracts and is therefore perfectly hedged against any uncertainties in spot prices.

Similarly, assume that a generator has sold a standard forward contract and a Nordic CfD, both with volume Q_s. Its cash flows are shown in Table 4-17. In this case the generator fixes its revenue to the prices of forward contracts.

Table 4-17. The cash flows of a generator in the delivery period resulting from the sale of a forward and a Nordic CfD.

	Forward market	CfD	Day-ahead market	Total cash flow
Generator is paid:	$Q_s\, p_f$	$Q_s\, p_{CfD}$	$Q_s\, AP_A - Q_s\, SP$ $-Q_s(AP_A - SP)$	$Q_s(p_f + p_{CfD})$

Another contractual arrangement is when a generator in area *A* enters into a contract to sell electricity to a consumer in another area *B* at the price P_C as shown in Table 4-18. The congestion fee is paid by the generator. In this market there are no FTRs available so the generator must use Nordic CfDs. A synthetic FTR is replicated by buying one CfD for the delivery area (*B*) and selling one CfD for the generation area (*A*). The payoff for 1 MW is:

$$FTR = (AP_B - SP) - (AP_A - SP) = AP_B - AP_A \tag{4.10}$$

As a result, the generator is able to hedge perfectly against the area price differential at a fixed cost of $Q_s(p_{CfDB} - p_{CfDA})$.

Table 4-18. The cash flows of a generator from a bilateral trade while hedging against the congestion fee.

	CfDs	Bilateral contract	Day-ahead market	Total cash flow
Generator is paid:	$-Q_s\, p_{CfDB}$ $+ Q_s\, p_{CfDA}$	$Q_s\, P_C$	$Q_s(AP_A - AP_B)$ $+Q_s(AP_B - AP_A)$	$Q_s\, P_C - Q_s\, p_{CfDB}$ $+Q_s\, p_{CfDA}$

4.5 Optimal hedging

Traditionally, hedging can be done by entering an identical, but opposite position to offset all risk. One replicates the risky asset by taking a short position in a forward instrument if the relationship between the prices of the two assets is linear. It can be shown (Hull, 2003) that the optimal hedge ratio for a player that wants to hedge its spot (or day-ahead) position (*S*) is to purchase the amount h^* of forward (*F*) contracts:

$$h^* = \rho_{SF} \frac{\sigma_S}{\sigma_F} \tag{4.11}$$

where σ is the volatility of the assets and ρ is the correlation between the assets. The returns of both the spot and the forward can be estimated from historical data.

The variance will then be a natural risk measure and variance minimization while holding the mean return constant is appropriate. The optimal hedge can be illustrated when the underlying asset is a price differential $P_{PD} = P_{AP} - P_{SP}$ between the area and System Price following the methodology utilized by Tanlapco et al. (2002). The purpose of this hedging is to insulate from price variations. Assume that the hedge is for one MWh and that the market player wants to trade at different locations. The value of the hedge (*H*) is:

$$H = P_{AP} - P_{SP} + h\ [F_{CfD,t-1} - F_{CfD,t}] \tag{4.12}$$

where *h* represents the number of MWhs of CfDs that are used for hedging (i.e. the hedge ratio) while $F_{CfD,t}$ and $F_{CfD,t-1}$ are the prices of CfDs at time *t* and *t*-1 respectively. If *h* is negative, then the player buys forward contracts at time *t*. Conversely if *h* is positive it sells forward contracts at time *t*. A value *h* equal to 1 means that the company is fully hedged (i.e. riskless hedge). Hedging is performed in a two-period setting and the player plans to sell *h* of the closest (*t*-1) forward contract. At time *t* when the anticipated spot market transaction occurs, the player closes out its forward position by purchasing the same forward contract at time *t*. This avoids physical delivery of the forward contract. The derivation of the optimal hedge is done in a minimum risk framework of a risk-averse company.[73] The mean and the variance of the hedge are shown as:

$$\begin{aligned} &E[H] = E[P_{AP}] - E[P_{SP}] - hE[F_{CfD,t}] + hF_{CfD,t-1} \\ &Var[H] = \sigma_{SP}^2 + \sigma_{AP}^2 + h^2\sigma_{CfD,t}^2 + 2h\rho_{SP,CfD,t}\sigma_{SP}\sigma_{CfD,t} \\ &-2h\rho_{AP,CfD,t}\sigma_{AP}\sigma_{CfD,t} - 2\rho_{SP,AP}\sigma_{SP}\sigma_{AP} \end{aligned} \tag{4.13}$$

Since the price of the CfD is known at *t*-1. σ is the standard deviation of the price. The variance is minimized with respect to the hedge ratio[74] when:

[73] One reason why a risk-minimization framework is acceptable is that for a highly risk-averse agent, the problem of maximizing a mean-variance utility function collapses into a variance-minimization problem.

[74] In the last equation it was used:

$$\rho_{APSP,CfD,t}\sigma_{APSP} = \frac{COV(AP-SP,CfD_t)}{\sigma_{APSP}\cdot\sigma_{CfD_t}}\cdot\sigma_{APSP} = \frac{COV(AP,CfD_t)}{\sigma_{AP}\cdot\sigma_{CfD_t}}\cdot\sigma_{AP} - \frac{COV(SP,CfD_t)}{\sigma_{SP}\cdot\sigma_{CfD_t}}\cdot\sigma_{SP}\ .$$

$$h^* = \frac{(\rho_{AP,CfD,t}\sigma_{AP} - \rho_{SP,CfD,t}\sigma_{SP})}{\sigma_{CfD,t}} = \frac{\rho_{APSP,CfD,t}\sigma_{APSP}}{\sigma_{CfD,t}} \tag{4.14}$$

where σ_{APSP} is the standard deviation of the difference between the area and System Prices, and $\rho_{APSP,CfD,t}$ is the correlation between the area/ System Price differential and the CfD price. The greater the covariance between the spot and Nordic CfD prices, the higher the forward market position for every MWh to be sold in the spot market, all else being equal. Conversely, if the variance of the CfD prices is high, this tends to lower the CfD position. The hedge is riskless (h=1) when $\sigma_{CfD,t} = \rho_{APSP,CfD,t}\sigma_{APSP}$. In practice, performing the optimal hedging strategy would require a liquid market where trades could be conducted whenever there was a need.

We can derive the corresponding hedge for two forward contracts for two different regions:

$$H = P_B - P_A + h_1[F_{B,t-1} - F_{B,t}] - h_2[F_{A,t-1} - F_{A,t}] \tag{4.15}$$

If h_1 is negative the trader buys forward contracts at time t and if h_1 is positive it sells contracts at time t. The opposite is the case for h_2. Similarly the mean and the variance of the hedge are:[75]

$$\begin{aligned}
&E[H] = E[P_B] - E[P_A] - h_1 E[F_{B,t}] + h_1 F_{B,t-1} + h_2 E[F_{A,t}] - h_2 F_{A,t-1} \\
&Var[H] = \sigma_A^2 + \sigma_B^2 + h_1^2\sigma_{FA}^2 + h_2^2\sigma_{FB}^2 - 2\rho_{A,B}\sigma_A\sigma_B - \\
&-2h_1\rho_{B,FB}\sigma_B\sigma_{FB} + 2h_2\rho_{B,FA}\sigma_B\sigma_{FA} + 2h_1\rho_{A,FB}\sigma_A\sigma_{FB} \\
&-2h_2\rho_{A,FA}\sigma_A\sigma_{FA} - 2h_1h_2\rho_{FA,FB}\sigma_{FA}\sigma_{FB}
\end{aligned} \tag{4.16}$$

where FA and FB are referred to time t.

The first-order conditions for optimality are:

$$\begin{aligned}
&\underset{h_1}{Min}\ \ Var[H] = 2h_1\sigma_{FA}^2 + 2\rho_{B,FB}\sigma_B\sigma_{FB} + 2\rho_{A,FB}\sigma_A\sigma_{FB} - 2h_2\rho_{FA,FB}\sigma_{FA}\sigma_{FB} = 0 \\
&\underset{h_2}{Min}\ \ Var[H] = 2h_2\sigma_{FB}^2 + 2\rho_{B,FA}\sigma_B\sigma_{FA} - 2\rho_{A,FA}\sigma_A\sigma_{FA} - 2h_1\rho_{FA,FB}\sigma_{FA}\sigma_{FB} = 0
\end{aligned} \tag{4.17}$$

The second derivatives with respect to h_1 and h_2 are positive, so a minimum is found. Solving for h_1 and h_2 gives:

$$\begin{aligned}
&h_1^* = \frac{1}{\rho_{FA,FB}\sigma_{FB}}\left\{\frac{1}{\sigma_{FA}^2(\rho_{FA,FB}^2 - 1)}[\sigma_{FA}^2(\rho_{B,FA}\sigma_B - \rho_{A,FA}\sigma_A)\right. \\
&\left.+\rho_{FA,FB}\sigma_{FB}^2(\rho_{B,FB}\sigma_B + \rho_{A,FB}\sigma_A)] + \rho_{B,FA}\sigma_B - \rho_{A,FA}\sigma_A\right\}
\end{aligned} \tag{4.18}$$

[75] The hedges are derived with respect to time *t*.

$$h_2^* = \frac{1}{\sigma_{FA}\sigma_{FB}^2(\rho_{FA,FB}^2 - 1)}\{\sigma_{FA}^2(\rho_{B,FA}\sigma_B - \rho_{A,FA}\sigma_A)$$
$$+\sigma_{FB}^2\rho_{FA,FB}(\rho_{B,FB}\sigma_B + \rho_{A,FB}\sigma_A)\}$$

The optimal hedge ratios for forward contracts are more complex than for CfDs. There are more uncertainties to monitor and hedge against.

4.6 Forecasting transmission congestion

As a starting point for analysis, current congestion pricing allows market participants to make an educated guess about the financial consequences of future congestion. However, it should be emphasized that current congestion may wrongly estimate future congestion. For example, in the US the national load growth is projected to be around 1.8% per year, but at the moment there are no incentives for investments in the national grid. If this continues to be the case, it will increase the frequency of transmission congestion and the magnitude of price differentials.

While it is impossible to predict future transmission congestion, it is possible to predict reasonable ranges. One starting point is to use the market price of an FTR. Another is the utilization of a rigorous generation and transmission model for forecasting locational prices.

4.7 Conclusions

This chapter has described different instruments for hedging against transmission congestion, and illustrated the use of financial transmission rights in the forward and bilateral markets. The Nordic market has been used to demonstrate the application of Contracts for Differences to hedge against transmission congestion. The cost of transmitting electricity (i.e. the congestion fee) between two locations is offset precisely by a higher price at one location. Similarly, selling to a low price location is offset by compensation. All trades between different regions then, are as profitable on average as local trades. To hedge against the congestion fee traders may purchase financial transmission rights or energy forward contracts if there are forward markets at both locations. If the contract price is less than the price difference between the high and low price location, the trade may be profitable.

If the objective is to minimize variance, a perfect hedge may be non-optimal. Expressions are derived for optimal hedges for Nordic CfDs and energy forward contracts with respect to different regions.

5 Markets for financial transmission rights[76]

This chapter surveys the markets for financial transmission rights (FTRs) around the world. FTRs are used to hedge the costs associated with transmission congestion. Currently these rights are in use in PJM, New York and New England. A variant of financial transmission rights, which has both a physical and a financial aspect, was introduced in California in 2000. FTRs are also planned for introduction in New Zealand. The chapter describes the features of the FTRs and the design of the different FTR markets. The focus is placed on how FTRs can be acquired, their advantages and disadvantages, and their market performance.

5.1 Introduction

According to Hogan (2003) transmission policy stands at the center of electricity market design. The basic principles are open access and non-discrimination. Financial transmission rights (FTRs) facilitate competitive open transmission access. The proposed standard market design in the US will reduce seams between regions and markets. Certain critical market activities require standardization in order to support efficient operation with open access and non-discrimination. The design includes an independent transmission provider, which administers a single tariff and operates the transmission system to support essential services. There should be a coordinated spot market for energy and ancillary services, which employs bid-based security constrained economic dispatch with locational marginal cost pricing. The design includes bilateral contracts with a transmission usage charge for each transaction based on the difference in the locational prices at the points of injection and withdrawal.

In these electricity markets, generators receive the locational price at the point where they inject power into the market and loads pay the locational price at the point where they have withdrawn power from the market. When the locational price differs between the generator and the load, the load or generator may be subject to congestion costs (i.e. congestion fees). FTRs as described by Hogan (1992) entitle the holders of FTRs to receive the value of congestion as established by the locational price difference. Thus, a holder of an FTR between a generator located at point A serving load at point B would be indifferent to any difference in the locational prices between the generator and load locations. The FTR would effectively reimburse the holder the same amount it pays in congestion costs. In the case of an FTR option, the payoff would be non-negative. FTRs are assumed to redistribute congestion costs which can considerable in the US power markets as illustrated in Figure 5-1. In PJM, FTRs are called fixed transmission rights, in New York transmission congestion contracts (TCCs), in California firm transmission rights, and in New Zealand and New England financial transmission rights.

[76] I am grateful for comments from William Hogan and Ann Stewart.

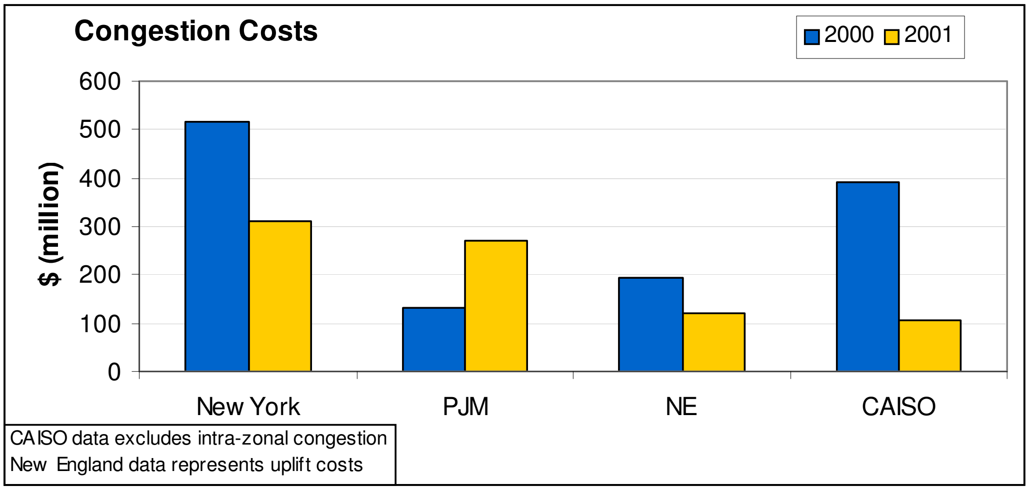

Figure 5-1. Congestion costs in US power markets (Singh, 2003).

FTRs have been used in the PJM (Pennsylvania, New Jersey and Maryland) Interconnection since April 1, 1998, in New York since September 1, 1999, in California since February 1, 2000, and in New England since March 1, 2003.

PJM has introduced FTR obligations and options, while New York and New England have introduced FTR obligations, and are now evaluating FTR options.

Various jurisdictions have chosen different FTR designs. PJM, New York, and New England have chosen purely financial contracts and Transpower New Zealand plan to do the same. California has introduced contracts that have both a physical and a financial element and that have similarities to flowgate rights (FGRs) and is currently evaluating congestion revenue rights, which are similar to firm transmission rights.

5.2 Market performance criteria

This chapter looks at the performance of the PJM and New York markets. Siddiqui et al. (2003) identify two issues that are important in evaluating financial hedging instruments. The first issue is how good the hedge is. The second issue is how efficient the market is. Important data in this regard are FTR prices and volumes (liquidity). An FTR is also a forward contract since it hedges against future uncertain locational prices. The market price of the forward contract should reflect the value of the underlying risky cash flow with a proper risk premium. According to Energy Security Analysis (2001) the price level of a forward contract is driven by the volatility of prices, the number of competitors in the market and the credit standing of the counterparties. Illiquid markets will result in higher premiums compared to liquid markets.

A proper relationship between the forward price and the underlying asset is achieved through arbitrage. This may be more difficult when dealing with FTRs. The large number of possible FTRs gives relatively low liquidity. There are few secondary markets that enable reconfiguration and reselling. The issuer of FTRs is usually an independent system operator (ISO). The FTRs are supposed to redistribute the congestion charges collected by the ISO during constrained conditions. In issuing

FTRs, an ISO would use a simultaneous feasibility test, which ensures that the total amount of FTR issued can be provided under expected network conditions. If the issued FTRs meet this test under the same network capacity, then the ISO will collect sufficient revenues to cover all FTR payments. The linkage between the simultaneous feasibility test and FTR revenue sufficiency is an important factor in preserving the quality, value, and amount of the FTR hedges. If the test is not met, revenues may be insufficient to cover payments to FTR holders. In the case of obligations, the test is easy to perform, but for options the computational demands are more substantial.

To evaluate whether the FTRs offer simultaneous feasibility, the ISO utilizes a model grid to ensure that offered rights are met by the capacity of the dispatch grid under expected normal conditions. Accordingly, pricing and trading of FTRs is done through a central periodic auction. The interaction among the different FTRs through the simultaneous feasibility test makes the prices and the congestion rents highly interrelated. An efficient FTR market must anticipate not only the uncertainty in transmission prices, but also the shift in the operating point within the feasible region determined by the economic dispatch (Siddiqui et al., 2003).

The model grid that represents expected conditions may be an inaccurate description of the grid offered for dispatch, resulting in discrepancies between the congestion charges and the payoff to the holders of FTRs. Currently, the ISO redistributes excess congestion charges to the FTR holders in deficit payment periods and transmission service customers. Conversely, when there are deficit congestion charges, the ISO may reduce payments proportionally to FTR holders or require transmission owners to make up the deficit.

We compare FTR prices with the underlying asset by studying several examples of FTRs over time and locations.

5.3 The PJM market

The PJM market uses hubs for commercial trading. The hubs are a cross-section of representative buses and their prices are less volatile than a single point because they are weighted averages of locational marginal prices (LMPs). The three main hubs are:

- Western hub (111 buses)
- Eastern hub (237 buses)
- Interface hub (3 buses)

The Western hub is the most actively traded location. The day-ahead market in PJM (predominately Western hub) is considered to be the most liquid market in the USA.

5.3.1 History

PJM introduced locational pricing on April 1, 1998, and at the same time offered some players fixed transmission rights to hedge against price variations. An auction-based market for FTR obligations was introduced May 1, 1999 and options were introduced in June 2003. From 1999-2002 there has been an annual increase in congestion charges in the PJM system. The overall increase can be attributed to different patterns of generation, imports and load and in particular the increased frequency of congestion at PJM's Western interface which affects a majority of PJM load.[77]

Congestion in PJM was 58 percent higher in 2002 than 2001. This increase in measured congestion was partly due to the result of adding PJM-West facilities to the market, thus permitting the more efficient redispatch of local generation and making explicit the price differentials that resulted.

The significant increases in congestion suggest the importance of implementing the Federal Energy Regulatory Commission's (FERC) order to begin to identify areas where investments in transmission expansion could relieve congestion that may enhance generator market power and support competition.

5.3.2 Fixed transmission rights

As initially defined by PJM, this is a purely financial contract that entitles the holder the right to receive compensation (even with no intent to deliver energy) for any transmission congestion charges present in the day-ahead market. A fixed transmission right (FTR) can protect the physical players that have costs correlated with the congestion charges and hedge the basis risk. It is not possible for the players to hedge against price differences due to losses with the present FTRs. FTRs are also issued together with firm transmission service.

FTRs are available for any location for which PJM posts an LMP (bus, aggregate, hub, or zone). They may be designated from injection buses outside of PJM and withdrawal locations inside PJM, injection buses inside PJM and withdrawal locations outside PJM, or buses with injections and withdrawals within PJM. For each hour with constraints on the transmission lines, the holder receives a portion of the congestion charges that are charged by the PJM ISO. The amount received is equal to the difference between the sink (point of withdrawal) and source (point of injection) LMPs multiplied by the actual amount of power specified in the contract as shown in Equation (5.1).

$$\begin{aligned}&\text{Congestion charge} =\\&\text{MWh (day-ahead sink LMP - day-ahead source LMP)}\\&\text{Point-to-point FTR credit} =\\&\text{MW (day-ahead sink LMP - day-ahead source LMP)}\end{aligned} \tag{5.1}$$

An FTR obligation may give the holder revenues or expenses depending on the specified direction of the contract. It gives revenues when the direction is the same as the congestion (the price at the injection bus is lower than at the withdrawal bus) and expenses if it is in the opposite direction. In the case of an FTR option the payoff is positive if the direction is the same as the congestion and zero otherwise. If FTRs were a perfect hedge, FTR holders would receive a credit equal to the FTR capacity reservation multiplied by the LMP difference between the point of delivery and the point of receipt of the FTR, when constraints exist. This is termed the transmission credit target allocation (Equation (5.1)). FTRs are not necessarily a perfect hedge and in fact, FTRs have hedged the percentages shown in Figure 5-2 in 2001 and 2002.

[77] 75 percent of PJM load is affected.

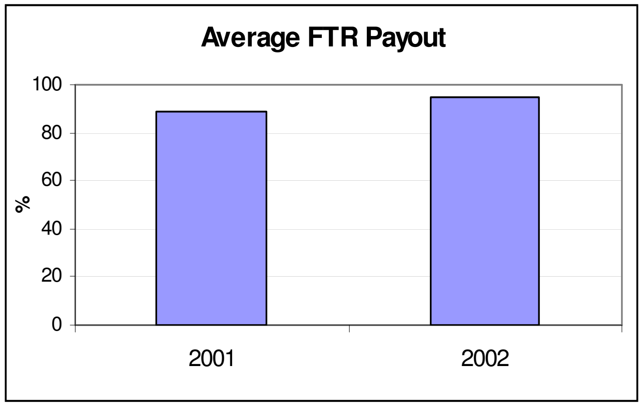

Figure 5-2. Average FTR payout for 2001 and 2002 (Singh, 2003).

The congestion calculations steps are:

- Calculate congestion charges in the day-ahead and balancing market.
- Determine FTR target allocation based on day-ahead LMPs.
- Allocate congestion charges based on target allocations.
- Distribute excess revenues.

If the target allocation is not satisfied, the credits from the FTRs are reduced proportionally. Excess congestion charges are distributed by covering hourly FTR deficiencies within a month and from the previous month within a calendar year. The remaining excess revenues are distributed pro rata to network and firm transmission customers at the end of the year based on demand charge ratio shares.

The FTRs have to meet the simultaneous feasibility test (SFT) that was created to ensure that the transmission system supports the outstanding amount of FTRs, given a normal operation situation. If the FTRs can support a normal operation condition and congestion is present, the congestion revenues will be sufficient for the ISO to cover the payments to the holder of FTRs.

The FTRs can be allocated in periodic yearly, monthly, weekly or daily auctions or in the secondary markets. The FTR secondary market is one in which holders and other entities that have acquired them sell FTRs on a bilateral basis. The contracts give coverage of congestion insurance for a month or longer. The buyers pay a premium for each right depending on the forecasted locational price differences. PJM evaluates proposals for new FTRs continuously. FTRs are also awarded to those who invest in transmission expansion, to the extent that the expansion allows additional FTRs that are simultaneously feasible with existing FTRs.

5.3.3 Acquisition and trading of fixed transmission rights

There are four ways to purchase FTRs:

- Network integration service (physical players).
- Firm point-to-point transmission service (physical players).
- Monthly FTR auctions (on- and off-peak).
- Secondary FTR market.

The time frame for the acquisition and settlement of FTRs in the PJM market is shown in Figure 5-3.

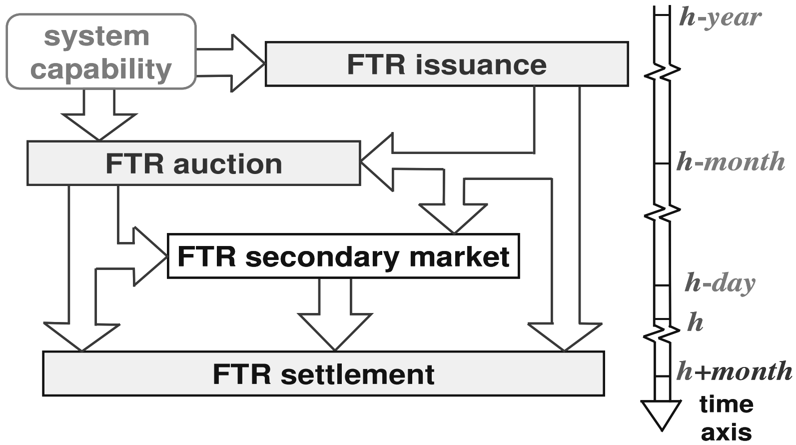

Figure 5-3. Time frame for the FTRs in PJM.

Transmission service customers who acquire network or firm point-to-point transmission service pay the embedded costs of the PJM transmission system. In return for paying these, the firm transmission service owners have the option to nominate for network resources[78] that they own or control to the zone(s) where their load was located in a quantity up to their coincident peak load within their zone.

Residual capacity is supplied in the market in two separate auctions: on-peak hours ending 0800 to 2300 and off-peak hours ending 2400 to 0700, including weekends and holidays. The supply of FTRs consists of the new issues plus any offers to sell by current FTR holders. Interested buyers may submit bids to buy FTRs. The secondary market and the auctions make it possible to trade existing FTRs independent of the initial allocation.

Annual FTR allocation processes provide FTRs only to network and firm point-to-point transmission customers. Initially PJM's secondary market allowed only the exchange of those specific FTRs. The initial process also provided that existing FTRs for network and firm point-to-point service had priority in subsequent annual FTR allocations and that the FTRs were continued. The network FTRs were held by the providers (utilities) of retail service to network customers. A load serving entity (LSE) that wished to serve customers in a congested area had difficulty competing with an incumbent utility holding FTRs. The new entrant faced the risk of congestion while the incumbent did not (PJM Interconnection, 2004).

To address this issue, effective as of June 1, 2001, PJM treated all requests for FTRs identically. The revised process allocated FTRs to network service customers based on annual peak load share rather than on historic priority. This resulted in opening access to FTRs to new LSEs that lacked historic FTRs.

[78] Network resources are defined as generators that meet the PJM deliverability requirement, and may be nominated to be a capacity resource service. Capacity resource is net owned capacity from owned (or contracted) generating resources that are designated and committed by a load serving entity to serve its obligation under the reliability assurance agreement.

However, the link between generation resources and ability to nominate FTRs remained. For example, two identical retail customers received different financial payments based on the generation resources owned by the LSEs that served them, as well as in the sequence in which those LSEs obtained the rights to claim such generation as capacity resource. The potential lack of any payments to those LSEs that acquired new load with an annual cycle remained as well.

Therefore, in 2002 PJM approved a significant change to the method of allocating FTRs (PJM Interconnection, 2004). The method was implemented for the planning year commencing June 1, 2003. The network FTR allocation process is discontinued and replaced with an annual FTR auction. This change provides a market evaluation of FTR value and permits all participants who value FTRs to bid a corresponding price to purchase them. Network customers is allocated FTR auction revenue rights (ARRs), which are the rights to collect the revenues from the FTR auction, based on the fact that network customers pay for the transmission system.

5.3.4 Network integration service fixed transmission rights

In PJM, all LSEs must buy network integration service for all their loads. This method forces customers to pay the entrance fee to the grid. In exchange for paying these fees, the LSEs receive some rights and obligations. They have an obligation to identify the production capacity that will deliver peak-load plus 20 percent. LSEs can choose to receive FTRs from the injection point (the generators), or the interconnection point with an external control area, to the withdrawal point for the aggregate load. FTRs are designated from unit-specific capacity resources, and cannot exceed the capacity contracted by the participant. The generators associated with the FTRs are referred to as designated network resources. The payoff from a network integration service FTR is:

$$\text{Network service FTR credit} = \text{MW}\,(\text{Day-ahead aggregate load LMP} - \text{Day-ahead generation bus LMP}) \tag{5.2}$$

The request process is annual, and the duration of the FTRs is from June 1 to May 31 of the following year. Modifications are allowed at any time. Network customers can choose combinations up to an amount equal to their peak load and can freely add or subtract FTRs as long as the amount of the outstanding FTR is feasible. Customers specify priority (between 1 and 4; 1 is highest) on their FTR requests. The maximum amount of FTRs for each priority is limited to a participant's 25 percent share of zonal peak load. If all FTR requests are not simultaneously feasible, the FTRs are then analyzed by priority level. Proration is required if all FTR requests within the same priority level are not simultaneously feasible. PJM can freely approve or not approve the proposed changes based on the SFT.

5.3.5 Firm point-to-point transmission service fixed transmission rights

Firm point-to-point transmission service means that the customer identifies two points and pays a fixed fee/tariff that basically equals the entrance fee for the network service. In exchange, the customer may receive an FTR between the two points and request a volume up to the transmission service capacity level. Firm customers may receive FTRs for their transmission reservations and their bilateral contracts. The FTRs are for the same duration as associated firm point-to-point transmission service and can be requested annually, monthly, weekly or daily. The source may be a producer in PJM or an interconnection point with an external control area where power is injected. The load point may be one of the aggregated PJM buses or the point of interconnection with the external control area of the receiver.

The same approval process applies that is used in the network integration service. PJM approves all, some or none of the proposed FTRs based on SFT.

5.3.6 Auction revenue rights

ARRs are long-term rights and are allocated to firm transmission service consisting of network integration service and firm point-to-point transmission service. ARRs are acquired for one year and are allocated for the entire capability of the transmission system. ARR holders are entitled to the price difference between the sink and source LMPs established in the FTR auction times the numbers of ARRs they hold.

The maximum amount of ARRs is limited to the peak load responsibility of a participant within a zone. ARRs must be designated from unit-specific capacity resources to aggregate loads. The ARRs requested from capacity resource cannot exceed the capacity value contracted by the participant. Network customers specify priority (between 1-4) on their request (each priority level is limited to 25 percent of network service load share).

All ARR requests are tested for feasibility. If all FTR requests are not simultaneously feasible, the FTRs are then analyzed by priority level. All ARR requests within the same priority that are not simultaneous feasible are prorated. ARRs are allocated proportionally to the MW requested and inversely to their effect on constraint.[79]

The holder can convert the ARR into an FTR by “self-scheduling” the FTR into the annual auction on the exact same path as the ARR. It may reconfigure ARRs by bidding into the annual auction to acquire FTRs on an alternative path or for an alternative product. It may also retain allocated ARRs and receive associated allocation of revenues from the annual auction.

Moreover, from March 2004 ARRs are allocated to firm transmission service customers annually in a two-stage allocation process. ARR requests are no longer required to have a unit-specific capacity resource as a source. Likewise, the annual FTR auction is a multi-round auction. Stage 1 assigns candidate ARR sources for each zone from resources historically designated to serve load in the zone. Stage 2 is a 4 round iterative approach which allows LSEs to request additional ARRs from a variety of potential ARR source points. ARRs allocated for the planning period is reassigned daily on a proportional basis within a zone as load switches between LSEs within the planning period (PJM Interconnection, 2004). Some benefits of the revised annual FTR allocation are:

- Protects native load utilization of the transmission system.
- Provides flexibility to adjust hedging paths annually.

[79] ARR trades are allowed between affiliates only and must be completed prior to the opening of the annual auction. Network service peak load associated with the initial allocation of ARRs will also be transferred to the new holder for the purpose of reassignment.

- Continues to allocate property rights to firm transmission customers through ARRs.
- Supports retail programs by reassigning ARRs/FTRs as load switches between LSEs within the planning period.

5.3.7 Monthly auctions

After the initial allocation of the network- and point-to-point transmission service FTRs, an auction is held where any existing FTR or residual capacity can be traded to create new FTRs. PJM members and transmission service customers can submit bids to purchase residual FTRs and submit offers to sell existing contracts. The PJM ISO determines the winning offers and bids by maximizing the total surplus without violating SFT. Participants submit bids for capacity of service for a specified injection/withdrawal bus pair, aggregates, hub or zone internal or external to PJM. PJM arranges monthly auctions (FTRs have one-month duration), which allow a reconfiguration of the total amount of rights.

The auction period opens 15 days before the FTRs are active. PJM calculates and informs about non-simultaneous possible FTRs for the PJM grid and the external connection points. The bids are checked and rejected bids are sent back to the holders for correction and new bidding. The bidding closes 10 days before the FTRs are active. Then the bids are evaluated according to SFT. The SFT decides a new number of “possible” FTRs by calculating a market price for each bus, selecting the highest bid-based value combination of feasible FTR paths. The price of an FTR path is the difference between the injection and withdrawal point market clearing prices.

5.3.8 Market performance

A major limitation to trading of FTRs is the lack of multiple requesters with the same injection and withdrawal buses. The monthly auction market was introduced to increase the liquidity of FTRs. An increase in liquidity should occur when offering a mechanism for auctioning the residual FTR transmission capacity and increasing the supply of FTRs.

Buying bids, volume and revenue have increased, reflecting the willingness of buyers to pay higher prices for residual system capacity because of increased congestion. In the period May 1999-December 2002, 87 percent of the FTRs issued by the PJM ISO were of the network type and 1 percent were of the point-to-point type.

PJM’s 2002 annual market report (PJM Interconnection, 2003) indicated that the FTR market was competitive in 2002 and succeeded in its purpose of increasing FTR access. There was a steady increase in the capacity of cleared FTRs and cleared FTR auction prices.

Over the life of the FTR auction, the bid volume has exceeded the offer volume by nearly a 10:1 ratio, 45000 versus 5500 MW per month on average (PJM Interconnection, 2003). The average bid and offer volumes were 52000 and 7000 MW per month in 2002. Cleared bid volume ranged between 3900 and 6400 MW per month during the 2000 to 2002 period, while the cleared offer volume ranged between 2200 and 5200 MW per month during the same period. Approximately two-thirds of the cleared bids were supplied from the cleared offers while one third drew on residual system capacity.

Prices in the FTR auction rose from \$356 to \$369 MW per month. Auction FTRs increased from an average of 3 percent of all FTRs in 1999 to 11 percent on average in 2000 and 2001, to 20 percent in 2002. Auction FTRs peaked in November 2002 when 11263 MW of on-peak FTRs cleared, representing 29 percent of all FTRs for the month. The auction revenue has doubled in each of the subsequent years since 2000, increasing to \$1.2 million per month in 2002.

An evaluation by the PJM Interconnections Market Monitoring Unit (MMU) to FERC (PJM Interconnection, 2000) after the first year concluded:

- FTR auctions succeeded in increasing the supply of FTRs.
- The main mechanism in the auction functioned well and trading increased.
- FTR auctions can affect the timing of the grid revisions.

The timing of the grid revisions is important because any player knowing in advance about planned revisions of the grid can use the information to take positions in the auction market. Grid companies will also have knowledge of revisions before it is public information. It is questionable if the grid companies take positions in the FTR market based on such non-public information. If the planned revisions increase congestion, the grid companies gain extra revenue from the contracts purchased before the revisions. One complaint was brought before the MMU, but no proof was found.

MMU proposed to PJM that all the grid owners must inform the market about the revisions at least two days prior to the auction closure. MMU also proposed a penalty for providing insufficient information about revisions. Grid owners must pay back any revenue from their revisions and they must give an updated plan of revisions one year ahead.

5.3.9 Payoffs and prices

The payoff from purchasing on-peak FTRs was calculated between 6 pairs of locations over the year 2002 in Figure 5-10 and Table 5-5 in the appendix. The payoff is defined as the difference between the average monthly point-to-point FTR credit target allocation and the monthly FTR clearing price (in \$/MWh). For these 6 FTRs, the payoff is positive for all except for one FTR. The standard deviation of the FTRs is higher than the average, implying highly uncertain market expectations about transmission congestion. During the year there are both negative and positive monthly payoffs. If the congestion charge target allocation exceeds the FTR credit target allocation parts of the FTR credit are reduced proportionally so both targets are met.

5.4 The New York market

New York introduced transmission congestion contracts (TCCs) September 1, 1999. The annual percentages of congestion hours for 2000 and 2001 are shown in Figure 5-4.

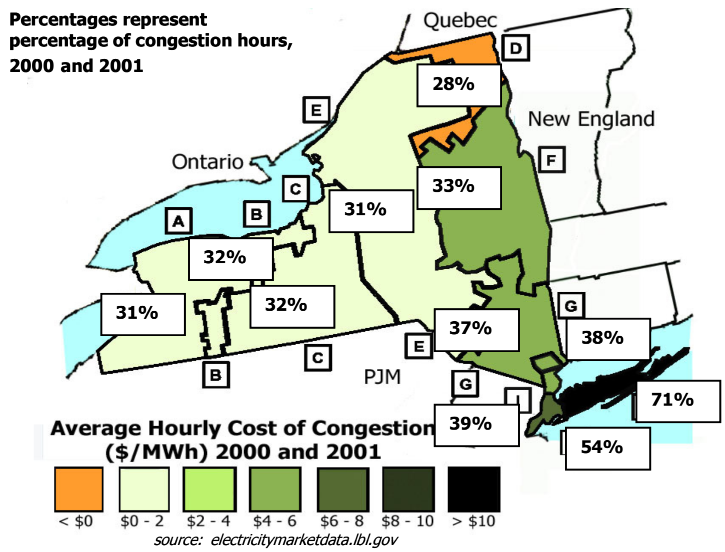

Figure 5-4. Congestion in the New York zones (Oren, 2003).

5.4.1 Transmission congestion contracts

Transmission congestion contracts (TCCs) are financial instruments for hedging against transmission congestion fees (New York ISO, 2003). The holder of the contract collects the congestion rent associated with transferring power from the source to the sink. The contracts are settled in the day-ahead market. In New York the locational prices are calculated based on an AC network (PJM uses a DC load flow model) with marginal losses. However, TCCs are only a hedge against congestion. The contracts are unidirectional and they become an obligation with reverse congestion.

The congestion charges apply uniformly whether the customers undertake a bilateral transaction or buy energy from the location-based marginal price (LBMP[80]) market. The congestion charges paid by the customers are collected in a TCC fund used to pay the primary holders of the TCCs and congestion paid to generators through LBMP. Over-collection of funds is allocated to the transmission owners to offset transmission system costs (TSC). Conversely, the transmission owners fund under-collection, and there is a true-up at the end of month.

Transmission owners are contractually bound to honor existing transmission facility and wheeling agreements. Parties to existing agreements are said to hold grandfathered rights. They must continue to pay transmission rates under existing contracts and they do not pay congestion costs, but may be subject to curtailments. Grandfathered transmission rights have until the implementation of the End State Auction (expected 2004) to convert the rights into TCCs. The total transmission capacity is divided among grandfathered transmission rights, grandfathered TCCs, existing transmission capacity for native load (ETCNL), and residual transmission capacity (RTC). A portion of RTC was allocated to transmission owners as residual TCCs prior to the formation of the New York ISO (NYISO).

[80]An LBMP is the same as a locational price or an LMP.

5.4.2 Acquisition and trading

TCCs can be purchased in MWs, and have durations of 6 months or 1 year. TCCs can be sold by direct sales, through a centralized TCC auction or via the secondary market. In the future FTRs will also be awarded to those who invest in transmission expansion. Direct sales are allowed by FERC but not exercised by the transmission owners.

Available TCC transmission capacity is offered to qualified market players through an auction process managed by the NYISO. The auction provides a means for market players, through their bidding preferences, to determine which set of TCCs will be awarded. It also allows primary holders to release the system transfer capability associated with their TCCs into the auction process. Upon completion of an auction, the ISO collects payment for all TCCs awarded for each round and the residual revenue is allocated to the transmission owners.

5.4.3 Auctions

The auctions have different stages:

- Phase 1: Two stages, multi-round auctions where stage 1 is a multi-round historical auction, and stage 2 is a single-round auction. It offers TCCs for specified durations in sub-auctions (historically) with 2 classes for each auction. The auction is conducted prior to each capability period (i.e. the minimum duration of the TCC).
- Phase 2: End State Auction for long-term TCCs. The annual auction will be implemented in 2004, and is a single-stage multi-round auction. Bids submitted by players determine the durations of TCCs purchased. The ISO then determines the minimum and maximum durations for TCCs sold and the period (on peak, off-peak). Later, an auction may be conducted semi-annually to sell 6-month TCCs. The End State Auction will replace the Phase 1 auction.

TCCs purchased in stage 1 can be turned around and released at the discretion of the seller in given stage 2 rounds. The players can also bid on system transfer capability released in stage 2. The process starts 45 days before the auction period (i.e. the settlement period). The auction is conducted over 30 days consisting of two stages. Stage 1 usually has 4 rounds, and stage 2 has 1 round. This process enhances price discovery and avoids fire sales. Two weeks in advance the ISO posts the number of rounds to be conducted in each stage; the system transfer capability; power flow model; non-simultaneous closed interface limits; the accumulated LBMP congestion component per MW; and any special rules or conditions. One week in advance TCC holders and the NYISO enter their submissions. Six days in advance data are posted and then the auctioneer is ready to receive bids. The total system transfer capability is divided in equal portions among each round, for a total of 4 rounds.

Reconfiguration auctions are also held monthly in a single round. The duration of the TCCs sold is one month. The TCCs offered by primary holders capture short-term changes in transmission capacity. Primary holders may re-sell their TCCs in the secondary market. In 2002 there were spring, summer, autumn and winter (parts of 2003) auctions. The spring and autumn auctions consisted of 6-month TCCs that were auctioned in 4 rounds plus one reconfiguration round (i.e. stage 2), and annual TCCs that were auctioned in 2 rounds plus one reconfiguration round. The summer and winter auctions are monthly reconfiguration auctions.

Each TCC has a specific source and sink. The source and sink may be a generator bus, a New York control area zone, the NYISO reference bus, or an external proxy bus. This creates great diversity in the TCCs that can be formulated, and because of that, makes trading TCCs somewhat limited. With such diversity in TCCs there is less chance that one party (seller) will have the exact TCCs that another party (buyer) desires. The concept of "unbundling" addresses the diversity issue by unbundling a TCC into standard components, each of which is a TCC. Because there is less diversity in the standard components, many believe that standard component, or unbundled, TCCs will be easier to trade, thus increasing the liquidity of the TCC market. The standard components of a TCC are:

- TCC from source to the zone containing the source
- TCC from source zone to sink zone
- TCC from source zone to source

When a TCC is unbundled into standard components, the original TCC is replaced by up to three TCCs as illustrated in Figure 5-5. The new TCCs retain the same capacity as the original. All TCCs sold in the spring 2000 initial TCC auction have been unbundled into their basic components effective as of September 1, 2000.

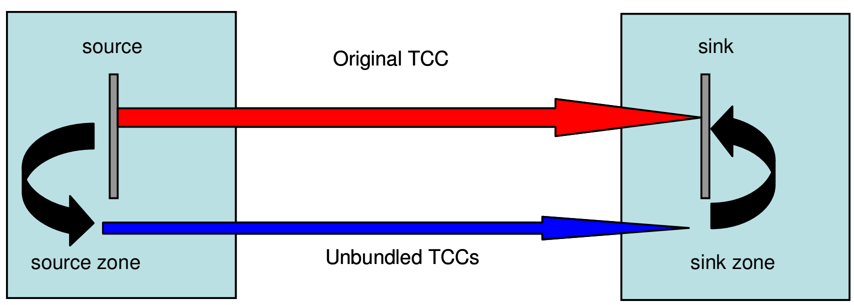

Figure 5-5. Unbundling of TCCs.

5.4.4 Market performance

In Figure 5-6 we show the auctioned volumes of TCCs. The auctioned volume increased almost 120 percent in 2000, around 50 percent from 2000 to 2001, and almost 9 percent from 2001 to 2002, reaching 140000 MW. The distribution of the TCC prices during 2002 is shown in Figure 5-7.

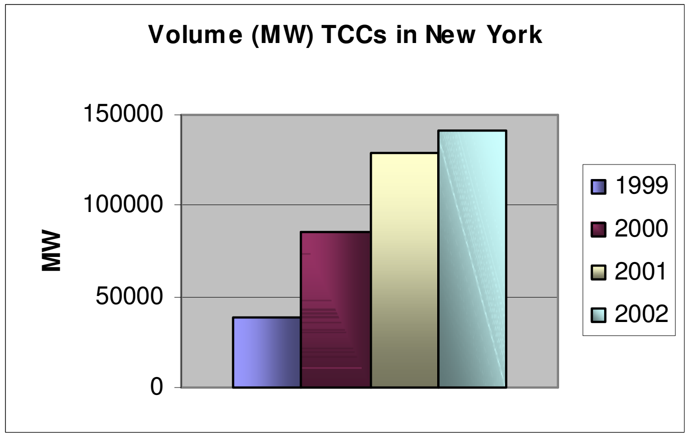

Figure 5-6. Annual volume in MWs of auctioned TCCs in New York.

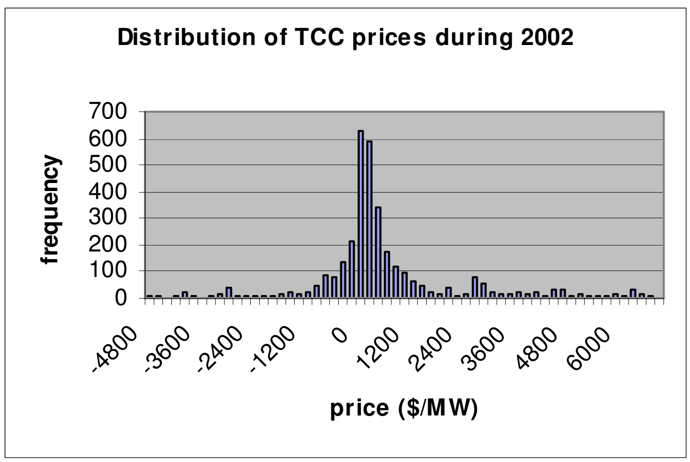

Figure 5-7. Price distribution of TCCs during 2002.

In Table 5-6 in the appendix we calculated the average auction prices and the average of the locational prices during the settlement period for some selected TCCs. There are discrepancies between the TCC price and the underlying locational prices, resulting in over- or under-collection of funds. When there is under-collection holders are honored the residual payment.

Siddiqui et al. (2003) analyze the TCC prices from the four initial auctions in 2000 and 2001. They find that the market performs relatively well. For example, buyers of TCCs predict congestion correctly most of the time. However, the TCC market does not appear efficient at hedging complex transactions involving larger exposures (greater than $1/MWh) or across multiple congestion interfaces. In this case TCC buyers pay prices including an excessive risk premium which is far from being reasonable. Siddiqui et al. also find no evidence through cumulative analysis that the market players learn how to use the TCC more efficiently over time. These results might be symptomatic of a new market with rules unfamiliar to most market players.

Likewise, arbitrage of price differences might not be possible because of illiquidity, risk aversion, and fear of regulatory intervention (Siddiqui et al., 2003).

5.5 The California market

California introduced firm transmission rights[81] on February 1, 2000. California chose a model in which the California ISO (CAISO, 2003) auctions the contracts.

5.5.1 Firm transmission rights

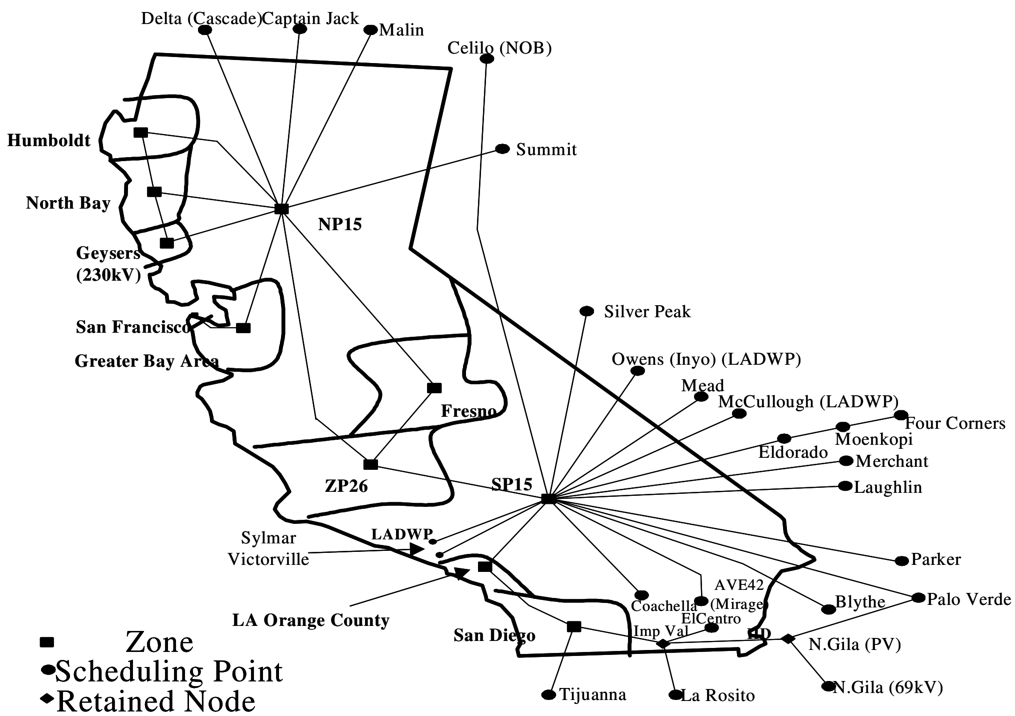

Figure 5-8. The California control area (Singh, 2003).

California uses zonal pricing, meaning that buses within an area with no or little congestion are grouped into zones as shown in Figure 5-8. In the near future they will introduce locational marginal pricing and congestion revenue rights as a part of the market reform MD02 (CAISO, 2003). The FTR in California has one financial and one physical aspect. The contract gives the holder the right to transfer power and at the same time receive the potential share in the distribution of usage charge revenues collected by the ISO due to congestion between two predefined areas. Together these aspects amount to a lease.

The holder of the contract receives the contract quantity times the shadow price on available transmission capacity (ATC) on a specific flowgate associated with a transaction (in the day-ahead market) when the congestion is in same direction as specified in the contract. The FTRs give the users of the ISO-controlled grid a hedge (that might be perfect) against hourly variations in the costs due to transmission

[81] The financial part of firm transmission rights is similar to a flowgate right.

congestion. FTRs do not entitle holders to usage charges generated by counter-scheduling.

FTR holders have priority in the scheduling of energy across interfaces in the day-ahead market. Holders of FTRs who do not use the contract, lose the scheduling priority but keep the associated congestion payment.

The amount of FTRs auctioned is equal to the ATC at the 99.5 percent level. This implies that the amount of FTRs outstanding approximately equals the actual generation and allows the ISO to allocate the outstanding capacity in the real-time power markets both hourly and daily.

If the transmission capacity on a line is reduced, the outstanding amount will not match the actual transmission capacity. All generation without FTRs will then be denied transmission. After that, the generation with FTRs will be constrained proportionally with regard to priority (if all the FTRs have the same priority).

5.5.2 Acquisitions and trading

The FTRs are provided in an annual auction and have a duration of one year. The auction is conducted in mid-January and FTRs are settled from April to March of the following year. The holders of the FTRs can sell the contracts in the secondary and in the hour-ahead markets for a specified price by using adjustment bids. This gives players without FTRs the opportunity to buy transmission in the hour-ahead market from the holders or the ISO.

The surplus from the auction goes to the owners of the transmission lines (the transmission operators) to cover a part of the fixed cost of the underlying grid. The higher the surplus, the lower the connection fee for consumers.

5.5.3 Auctions

The initial period for the primary auction is one year. Within that limit the ISO offers the option to create or eliminate new zones. FTRs with a duration of less than one year were too complex for the ISO to administer and reduced the incentives for creating liquid markets.

The amount of issued FTRs is calculated by determining the ATC for a branch group,[82] in a specific direction for each hour over the past year. The hours are ranked from the highest to the lowest value, and the ATC is chosen at the 99.5 percent availability level. The value at 99.5 percent is the number of FTRs for sale.

5.5.4 Market performance

Table 5-1 shows the annual volume of auctioned firm transmission rights. The volume ranges from 9553-10475 MW and is relatively stable over time. Prices ranged from 165 $/MW to 17610 $/MW in 2002.

[82] A group of transmission branches that is treated as a single entity for purposes of running a congestion management market.

Table 5-1. Volume of auctioned firm transmission rights in the California market (there was no auction in 2000).

Year	Volume (MW)
1999	9553
2001	10475
2002	10419
2003	9559

5.5.5 Congestion revenue rights

The California ISO is currently evaluating congestion revenue rights (CRRs), which are similar to what FERC proposed in its standard market design (FERC, 2003). Transmission capacity will be awarded, allocated, and auctioned as CRRs in the following priority sequence: non-converted existing transmission contracts (ECTs), converted ECTs, ECTs under conversion, LSE nominations and CRR bids. Point-to-point CRRs are physical (scheduling rights) and financial rights in the day-ahead market. CRRs are defined between buses or hubs and are forward contracts in which the holder is obligated to receive (or pay) the difference in LMP between the sink and source times the contractual volume. CRRs can also be offered as obligations or options to converted ECTs. Network service rights (NSRs) are forward contracts for fixed power transfers from multiple sources to multiple sinks. The sum of power injections at sources equals the sum of power withdrawal sinks. The sources and sinks can be network buses or hubs. NSRs are financial obligations and solely financial (at this time). They will be allocated to LSEs as obligations and can be acquired through CRR auction and via the secondary market. CRRs can be unbundled as point-to-point CRRs for trading purposes.

5.6 The New England market

New England introduced financial transmission rights (FTRs) in March 2003.

5.6.1 Financial transmission rights

The FTR is a financial instrument that entitles the holder to receive compensation for congestion costs that arise when the transmission grid is congested in the day-ahead market, and differences in day-ahead LMPs result from the dispatch of generators to relieve congestion (New England ISO, 2002). If a constraint exists in the network, the holders receive a credit target allocation based on the FTR MW quantity and the difference between the congestion components of the day-ahead sink and source LMPs. The holder receives credit regardless of who delivered the energy or the amount delivered across the path designated in the FTR. Similarly, an FTR is a financial obligation if the congestion flows in the opposite direction of the FTR.

If the monthly total of the positive FTR target allocations is less than the transmission congestion revenue, holders receive a congestion credit equal to their total positive FTR target allocations. If the monthly total of the positive FTR target allocations is more than the transmission congestion revenue, FTR holders receive shares of the monthly congestion revenues proportional to their total positive target allocations.

5.6.2 Acquisitions and trading

FTRs can be acquired or sold in auctions or in the secondary markets. Bilateral trading may be done independently or through ISO-administered bilateral trading. Reallocation also occurs in the auctions and secondary markets. The purchaser of an FTR in a bilateral transaction outside these markets receives only a contractual right against the seller of the FTR and has no rights or obligations in ISO settlement or in the energy market.

5.6.3 Auctions

The auctions are characterized by start and end dates, and are on- (ending hours 0800 to 2300 on weekdays) and off-peak (ending hours 2400 to 0700 on weekdays, weekends and holidays). The ISO conducts periodic auctions to allow eligible bidders to acquire FTRs. The SFT performed in the auction process ensures that there is sufficient system capability to support the FTRs sold and that congestion revenue is adequate to compensate the holders.

FTR auctions are introduced on a monthly basis, after which the ISO will conduct both longer-term and monthly auctions. The locations in the contracts are defined by LMPs at the source and sink and the contracts are awarded in tenths of a MW. The auction volume and revenue for the first three months are shown Figure 5-9.

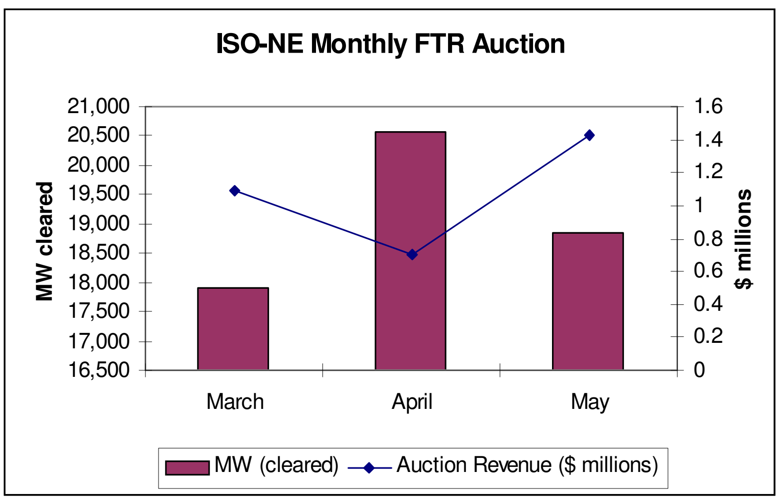

Figure 5-9. Auction volume and revenue for monthly FTR auction in New England (Singh, 2003).

Auction revenues are distributed to the FTR sellers and the ARR recipients. ARRs are awarded to entities (ARR recipients) paying for transmission upgrades which make it possible to award additional FTRs and allocate them to the entities responsible for paying congestion charges. A four-stage process determines the ARR of each entity based on its load share of all generation and its tie sources within the capability of the transmission system. Special recognition is given to certain contractual arrangements and the parties to those agreements.

5.7 The New Zealand market

A system with nodal pricing and a wholesale market was introduced in New Zealand in 1996. At the same time, players were offered a price differential hedging product as a hedge against the increased risk. Transpower New Zealand (the system operator) agreed to provide this product for a limited period. The product gave restricted insurance against nodal price differences and had minimum and maximum prices to reduce the counterparty risk for Transpower. The product was withdrawn in 1998, because there was little interest among the players. It was more natural to let other players provide the product.

In New Zealand, the congestion revenue is defined as the surplus from losses and congestion and is allocated among the users of the grid. In the present power system the system operator receives the congestion revenue. The system operator allocates the congestion revenue to the owners of the grid companies that are paying the sunk costs for transmission investments.

There is a debate in New Zealand about the introduction of financial transmission rights (FTRs). The industry says that Transpower has focused too narrowly on refining the concept, while ignoring broader issues and options. They also believe that there has been pressure to find a quick solution, rather than the appropriate solution. Opinions vary about who is entitled to the settlement surplus and has the right to develop an FTR and/or allocation regime.

5.7.1 Financial transmission rights

The proposed FTR will give the right to receive or the obligation to pay the difference in prices at the buses (or hubs) for which the hedge is written for a defined amount of MWs and a defined period (Transpower, 2001 and 2003). An FTR will be an obligation and will have payoff:

$$\begin{aligned} \text{Payoff} = \text{MW}\,(&\text{Day-ahead sink nodal price} \\ &- \text{Day-ahead source nodal price}) \end{aligned} \tag{5.3}$$

The nodal price contains both a congestion and loss component. Directional FTRs will consist of balanced FTRs (congestion) and spot FTRs (losses). Spot FTRs will represent injection at a bus (or hub) to make up any shortfall in forecasted losses. Both spot and directional FTRs will be auctioned.

FTRs will be funded through transmission losses and transmission congestion rents. Transpower will offer the FTRs at a no profit/loss basis so all income from FTR auctions and residual rents will be returned via lower charges to the parties that pay the sunk costs of the grid. FTR payments are reduced proportionally when there are deficit congestion rents.

5.7.2 Acquisition and trading

Today there are bilateral financial instruments to hedge against differences in nodal prices. Private players provide these products that have no effect on the physical market.

FTRs of 1-month duration will be auctioned monthly to all parties and can be traded freely in the secondary market. Later they may be offered for future months and longer durations. Together with the initial auction this will ensure that the FTRs are allocated to the players who value them most.

FTRs will be allocated for all new investments in the grid and will have duration equal to the lifetime of the investment. New investment FTRs may be offered into auction by the holder.

5.7.3 Auctions

After an introductory phase the FTR market will change to a 12-month forward market. FTRs could be sold for any volume (MW) and between every pair of buses or hubs, given that the SFT is met. For future periods, reconfiguration auctions will be held monthly. Existing FTRs could be offered back into these auctions and additional FTRs purchased. It is expected that the LSEs, consumers, and producers will value FTRs higher than the other players, since their revenues are correlated with the price differentials. The auctions will be designed to ensure that the congestion rent and the FTR payments will balance. However, to the extent that the grid offered for dispatch will be different from the auction grid, there will be a risk that the congestion rents for that dispatch period will not cover FTR obligations. In such an event the FTR payments will be scaled down pro rata. Careful grid design will minimize the risks. The FTR auction income will be allocated to those who pay the sunk costs of the grid and the income is expected to be less variable than the congestion rents.

5.8 Financial transmission right properties

Financial transmission rights define property rights and are a mechanism to hedge transmission price risk. Property rights provide market players with the financial benefits associated with transmission capacity and facilitate efficient use of scarce resources. Property rights are also a mechanism to reward transmission investments. The rights will give investors a tradable contract in return. The ability to hedge transmission price is an important feature in facilitating an efficient electricity market. Efficient pricing of FTRs through liquid trading provides economic signals for location of generation, load and transmission investments.

FTRs can be allocated in different ways (Lyons et al., 2002). First, they can be given to those who invest in transmission lines. For other market players there needs to be eligibility requirements for FTR ownership in the existing transmission system and in the secondary markets. The implemented solution depends on the market design and the decisions made in that market. FTRs for existing transmission capacity can be allocated in a number of different ways such as based on existing transmission rights or agreements, auctioned off, or so that their benefits offset the redistribution of economic rents arising from tariff reforms. An auction allocates the FTRs to those market players who value them highest. The revenues from an auction can be allocated to the transmission owners. In California transmission owners use them to pay off their transmission investments, and in New York they are used to reduce the transmission service charge. Reallocation can happen in the secondary markets. FTRs can also be allocated based on historical use and entitlements.

FTRs offer instruments for converting historical entitlements to firm transmission capacity into tradable contracts that keep the owners just as well-off as economically while enabling them to cash out when others can make more efficient use of the transmission capacity covered by these contracts. An attractive policy issue is that the FTRs offer a convenient path to competitive open transmission access. This is critical in establishing a competitive electricity market.

An important issue is the efficiency of the FTR market as pointed out by Siddiqui et al. (2003), where they compare the FTR auction prices to the prices they are settled against. Inefficient pricing of FTRs distorts long-term transmission price signals and will result in inefficient dispatch, inefficient location of generation and load, and inefficient transmission investments. Oren and Deng (2003) test if price discovery and learning lead to convergence of FTR auction prices to the value of the underlying asset. They simulate *n*-1 contingencies and load uncertainty in a test network to calculate the expected FTR value. They find that the FTR auction prices will depend on bid quantities or distribution of initially allocated FTRs. To achieve efficient pricing some hedgers holding FTRs covering their energy transactions must yield these instruments to speculators that will bid up the most profitable FTRs. Therefore, an allocation will preserve FTRs better than an initial auction. They also claim that imposing simultaneous feasibility on FTRs is too stringent.

Among researchers, there is consensus about the need to mitigate market power for any FTR auction to be efficient. The conclusion in the FTR literature is that generators can more easily exert local market power when transmission congestion is present.

5.9 Conclusions

This chapter has presented an overview of markets for transmission rights around the world (Table 5-2, Table 5-3 and Table 5-4). The design and the rules of these markets are changing continuously. The information is complex and therefore this overview presents the author's understanding of the markets at the current time.

Table 5-2. Advantages and disadvantages of FTR markets.

<table>
<tr><th>Market</th><th>Advantages</th><th>Disadvantages</th></tr>
<tr><td>PJM</td><td>Western hub liquid</td><td rowspan="5">No short-term hedges, lack of multiple requesters with the same injection and withdrawal buses decreases liquidity, potential exercise of market power</td></tr>
<tr><td>New York</td><td>Several rounds of auctions enhance price discovery and avoids fire sales, unbundling</td></tr>
<tr><td>California</td><td>Both physical and financial</td></tr>
<tr><td>New England</td><td></td></tr>
<tr><td>New Zealand</td><td>Hedge against losses</td></tr>
</table>

Table 5-2 shows the advantages and disadvantages of the FTR markets. One major disadvantage is that all FTRs are short-term hedges.

The numbers for trading volume indicate increased liquidity in the PJM and New York markets. However, the limited liquidity of FTRs in some regions inhibits trade. Efforts to increase liquidity should be made through trading hubs such as the PJM Western hub. Unbundling may also contribute to increased liquidity. The system in PJM has limited liquidity and transparency for annual FTRs. Auction revenue rights will allow for better liquidity because they are not tied to the holding of network load or resources. New York conducts auctions with up to 4 rounds for the same FTR.

There are also monthly reconfiguration auctions. This enhances price discovery and avoids fire sales.

Experience from the PJM market indicates that the process of allocating FTRs to utilities of retail service based on historic priority, inhibited competition because an entrant LSE had difficulties in acquiring FTRs. This problem was addressed by allocating FTRs to network customers based on annual peak load share rather than on historic priority. However, the link between generation resources and ability to nominate FTRs remained. From June 2003, the allocation of annual FTRs is according to a market valuation where players bid for FTRs (i.e. ARRs).

In New York grandfathered (historic) transmission rights are present. These are converted to TCCs in the End State Auction in year 2004. In this way TCCs offer mechanisms for converting historical entitlements to firm transmission capacity into tradable contracts.

Table 5-3. Comparison of FTR markets.

Market	PJM	New York
Contract	**Fixed transmission rights, financial, no hedge against losses, both obligations and options, auction revenue rights to transmission network customers**	**Transmission congestion contracts, obligations, no hedge against losses**
Contract duration	**1 month auction FTRs, annual network integration service FTRs, firm point-to-point transmission service FTRs have duration equal to the associated firm point-to-point service**	**6 months and 1, 2 and 5 year auction FTRs, monthly reconfiguration FTRs**
Acquisition and trading	**Network integration and firm point-to-point transmission service, auctions and secondary market**	**Auctions, secondary market**
Initial allocation	**Initially allocated to network integration service customers**	**Prior to the formation of the NYISO, there was an allocation of TCCs. In the first stage of this allocation, customers receiving service under existing transmission agreements were given the choice of converting their existing rights into either grandfathered rights or grandfathered TCCs. After these rights had been allocated and accounted for, existing transmission capacity for native load was allocated to some transmission owners. Once all of these had been accounted for, residual TCCs were allocated to the transmission owners.**
Auction design	**Monthly (on- and off-peak)**	**Seasonal (with several rounds), monthly reconfiguration auctions**
Liquidity, (volume traded 2002)	**Bid: 624 GW Offer: 84 GW**	**Total: 140 GW**
Congestion rents	**Excess rents distributed to deficiencies in other periods, deficit rents reduce payments proportionally**	**Excess rents offset transmission system cost, deficit rents covered by the transmission owners**
Distribution of auction revenues	**FTR auction revenues are allocated among the regional transmission owners in proportion to their respective transmission revenue requirements**	**All revenues received by transmission owners from the sale of grandfathered TCCs and residual TCCs, as well as excess auction revenues, are credited against the transmission owner's cost of service to reduce the transmission service charge**

The work has also studied the FTR prices for some selected pairs of locations. Limited studies indicate that there are discrepancies between the FTR price and the value of the underlying asset. The reason is that the model grid used in the auctioning of FTRs is an inaccurate representation of the dispatch grid. This is not surprising, because unforeseen shocks during settlement periods are bound to occur. Siddiqui et al. (2003) analyze the TCC prices from the four initial auctions in 2000 and 2001. They find that the market performs relatively well. However, the TCC market does not appear efficient at hedging complex transactions involving larger exposures (greater than $1/MWh) or across multiple congestion interfaces. In this case TCC buyers pay prices including an excessive risk premium which is far from being reasonable.

The information technology of today makes it relatively easy to collect and work through large amounts of data. It also makes it easier to design transmission rights and define the volumes. PJM designed a simultaneous feasibility test that ensures that FTRs are consistent with the possible schedules and the physical conditions in the grid.

Table 5-4. Comparison of FTR markets.

Market	California	New England	New Zealand
Contract	Firm transmission rights, financial with scheduling priority, option-like, no hedge against losses, congestion revenue right obligations and options will be implemented in the future	Financial transmission right obligations, no hedge against losses	Financial transmission right obligations, hedge against losses
Contract duration	1 year auction FTRs	Monthly auction FTRs	Monthly auction FTRs, investment FTRs have duration equal to the lifetime of the investment
Acquisition and trading	Auctions, secondary market, hour-ahead market	Auctions, secondary market, transmission upgrades	Auctions, secondary market, transmission expansion, entities paying congestion charges
Initial allocation	The initial allocation was through a primary auction of November 1999, in which FTRs equal to 100 percent of the operating limit at 99.5 percent availability were auctioned off. These FTRs were valid for a period of 14 months, from February 1, 2000 until March 31, 2001.	Monthly FTR auctions, longer-term auctions later	To be decided
Auction design	Annual	Monthly	Monthly, FTR for investments in the grid,
Liquidity, (volume traded 2002)	Total: 10.4 GW	Introduced March 2003, limited data available	To be implemented
Congestion rents	Excess rents partly cover the fixed costs of the grid, deficit rents reduce payments proportionally	Excess rents redistributed to FTR holders, deficit rents reduce payments proportionally	Excess rents redistributed to those who pay the sunk costs of the grid, deficit rents reduces payments proportionally
Distribution of auction revenues	The primary auction proceeds went to the participating transmission owners. Each participating transmission owner credited its FTR auction proceeds against its access charge	FTR auction revenues are distributed to sellers of FTRs and auction revenue rights recipients	

PJM differs from other markets because its ISO assigns parts of the financial rights directly to the transmission service customers who pay the embedded cost of the transmission grid. The allocation is more restrictive because customers only can request FTRs up to their transmission service level.

The contracts proposed for introduction in New Zealand include payments for losses. This means that an FTR gives the holder the right to the entire price difference between two buses, both the one due to losses and the one due to congestion. In New York an AC network is used, which takes losses into account, but the FTR does not hedge against losses. In most of the literature the transmission rights only give the right to differences in price due to congestion. Harvey and Hogan (2002) give an overview about how to design FTRs for hedging against losses.

The introduction of FTRs/TCCs in the different systems in the USA must be viewed in relationship to the organization of the market. Often private players own the central grid, but a system operator operates it. The FTR is a means to reduce the possibilities for the grid owners or system operators to exercise market power.

In all markets the FTRs are supposed to redistribute the congestion charges to the users of the transmission services. This creates incentives for transmission providers to maintain and expand the transmission grid, thus reducing congestion.

Appendix

PJM FTR prices

Table 5-5. Average payoff and standard deviation from selected FTRs in the PJM market in $/MWh during the year 2002.

FTR	Average payoff	Standard deviation
BAYONNE 138 KV COGEN1 PVSC 138 KV T-1	-0.06	0.12
BRUNNERI 230 KV DIES WHEMPFIE 138 KV PRIN_1	0.21	0.71
COLLINS 115 KV LD1 NEWBERRY 115 KV 1 BANK	1.13	4.15
WHITPAIN WHITEMAR 230 KV DBU6	0.75	1.40
HOMERCIT 20 KV UNIT 2 HOMERCIT 23 KV DUM2	0.07	0.55
DEANS PSEG	0.14	0.52

The payoff is defined as the difference between the average monthly point-to-point FTR credit and the monthly FTR clearing price (in $/MWh) and is illustrated in Table 5-5 and Figure 5-10. The prices are shown in Figure 5-11 and Figure 5-12. Table 5-5 shows that the average payoff during a year is positive for all FTRs except BAYONNE 138 KV COGEN1 PVSC 138 KV T-1. The standard deviation is higher than the average, implying highly uncertain market expectations about transmission congestion. During the year there are both negative and positive payoffs. The FTR COLLINS 115 KV LD1 NEWBERRY 115 KV 1 BANK has the highest payoff (13.91 $/MWh) in July 2002. Conversely the lowest payoff (-2.80 $/MWh in September) is for the same FTR. This FTR has the highest standard deviation of all contracts.

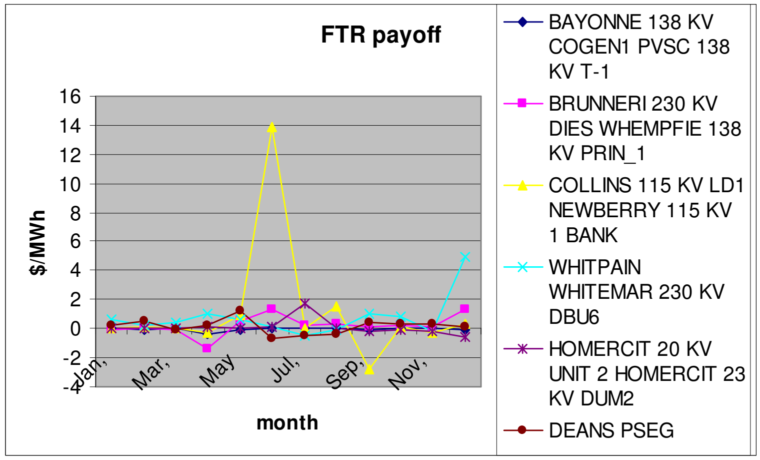

Figure 5-10. Payoff from selected FTRs in the PJM market in $/MWh during the year 2002.

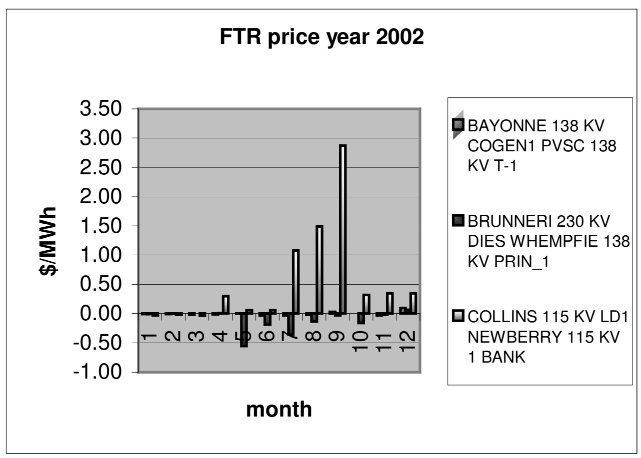

Figure 5-11. Selected monthly FTR prices during 2002.

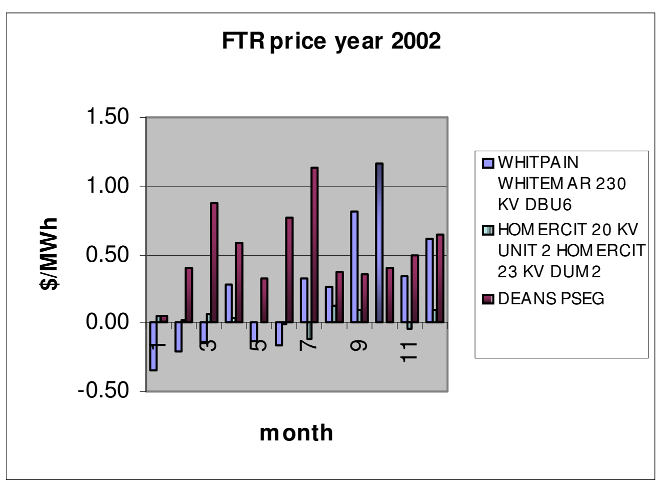

Figure 5-12. Selected monthly FTR prices during 2002.

New York TCC prices

Table 5-6 shows the **a**uction prices of selected TCCs and their associated spot prices in $/MWh in the New York market.

Table 5-6. Auction prices of selected TCCs and their associated spot prices in $/MWh in the New York market.

	Average traded price	Average of locational prices	Payoff
Spring 2002 auctions round 4 MHK VL – CENTRL	-0.01	-1.53	-1.52
HUD VL – N.Y.C	4.84	-8.38	-13.22
HQ-NYISO_LMBP_REF	-0.48	-0.24	-0.71
HUD VL – N.Y.C Jan. reconfig.	2.12	-0.65	-2.77
Feb. reconfig.	1.75	-0.13	-1.88
Mar. reconfig.	1.08	-0.92	-2.00
Jun. reconfig.	6.00	-9.12	-15.12
DUNKIRK_3 NEG WEST_LANCAS, Jan. reconfig.	-0.12	0.34	0.46
Feb. reconfig.	-0.09	0.29	0.38
Mar. reconfig.	-0.06	0.41	0.47
RAVENSWOOD_G-HUDSON Jan. reconfig.	-0.08	0.28	0.36
Feb. reconfig.	-0.05	0.09	0.14
Mar. reconfig.	-0.04	0.01	0.05
PJM-HQ_GEN_CHAT_DC Jan. reconfig.	0.68	1.55	0.87
Feb. reconfig.	0.37	1.02	0.65
Jun. reconfig.	-0.50)	0.35	0.85
Oct. reconfig.	-0.44	0.69	0.25

6 Utilizing MATPOWER in optimal power flow

This chapter demonstrates how MATPOWER, a MATLAB package (Zimmerman and Gan, 1997) can be used for optimal power flow (OPF) simulations. An OPF simulation calculates the active/reactive power generated and purchased at each bus and the nodal prices. The nodal prices are of special interest because they reflect the marginal value of generation and load at each bus (node). These prices are also called locational prices and are found to be the optimal prices, maximizing social welfare and taking transmission constraints and losses into account. They can provide the right incentives to market players and maximize social welfare. When transmission congestion is present, this creates market inefficiency, since cheap distant generation may be replaced by more expensive generation. There is particular interest in OPF as utilized by a centralized dispatcher, and the features relevant for the Norwegian and Nordic markets. Three cases are optimized and the chapter analyzes the economic consequences of different network topologies and transmission congestion.

6.1 Introduction

Deregulation has required a stronger focus on the financial aspects of the Nordic power market and a need for economic analysis of power transmission services.

The optimal prices in a transmission network are the nodal prices (Schweppe et al., 1988 and Hogan, 1992) resulting from an optimal power flow (OPF) performed by a centralized dispatcher (e.g. an independent system operator - ISO). The OPF model is implemented in parts of the United States (e.g. PJM), and in Australia and New Zealand. In the Nordic region area (zonal) pricing is used. This is a simplification and aggregation of nodal pricing. The Nordic power system does not include a central scheduling/dispatching entity, only a central power exchange (Nord Pool). Generators and loads schedule by self-dispatch. There is one power exchange and 5 transmission system operators (TSOs) in the Nordic region.

When congestion is predicted in Norway, two or more spot areas are defined. This procedure is called market splitting. In these cases, the players must specify their bids in the different spot price areas. Clearing at Nord Pool determines that the prices in the different areas are such that the power flows do not exceed the specified constraints. A surplus area will then receive a lower price than a deficit area. The difference between the respective area prices and the System Price is called the Congestion Fee.[83] Statnett (the Norwegian system operator) defines the fixed price[84] areas in Norway according to its information on the likely pattern of flows on the system for a certain period of time. Congestion inside the price areas is managed by use of counter trade.[85]

OPF in the context of nodal pricing is considered as well as how it can be used for area pricing. This chapter shows that even a simple system can give interesting results, when an economic analysis is conducted to the system.

[83] Statnett uses the term “Capacity Fee” (Norwegian: kapasitetsavgift).
[84] The number of price areas in Norway may be more than two.
[85] Counter trade is real-time congestion management by increased production (upward regulation) within the constrained area and decreased production (downward regulation) in the surplus area.

6.2 Optimal power flow and nodal prices

OPF is a technique that has been used in the electricity industry for several decades. The objective in OPF is to minimize generator operating costs.

6.2.1 Formulation of optimal power flow

The objective function is the total cost of real and/or active generation. The costs may be defined as polynomials or as piecewise-linear functions of generator output. The problem can be formulated schematically as:

Min (costs of active and reactive generation)

subject to

active power balance equations

reactive power balance equations

apparent power flow limit of line, from and to side

bus voltage limits

active and reactive power generation limits

To guarantee that the OPF can be solved, one of the zones (nodes) is assigned a zero phase angle by setting its phase angle upper and lower limits to zero (the swing bus). The post-contingency interface flow limits are included in the OPF. If all *n*-1 contingencies were considered, there would be a constraint for each line contingency for each interface.[86] This would make the problem size too large for efficient computation. To limit the number of constraints, the OPF is solved without contingency constraints, a contingency analysis is performed, and then the OPF is resolved with new constraints added only for those contingency outages that result in overloads, and only for the interfaces that are overloaded.

Generator cost functions are represented as quadratic functions:

$$C_i\left(P_{G_i}\right) = a_i + b_i \cdot P_{G_i} + c_i \cdot P_{G_i}^2 \tag{6.1}$$

where P_G is the produced power and *a, b* and *c* are constants. The quadratic cost functions make this OPF formulation a problem that can be solved with a quadratic programming (QP) algorithm. The QP algorithm used can accept upper and lower bound limits on each variable.

The DC OPF power flow model assumes that only the angles of the complex bus voltages vary, and that the variation is small. Voltage magnitudes are assumed to be constant. Transmission lines are assumed to have no resistance, and therefore no losses (Christie et al., 2000). This is a reasonable first approximation for the real power system, which can be considered only slightly nonlinear in normal steady state operation. In MATPOWER, a DC power flow is modeled by setting the resistance to zero for the transmission lines. An alternating current (AC) power flow is modeled by using values for both resistance and reactance.

[86] In practice the *n*-1 criterion is implemented in the OPF. Here a simplification is made.

In electricity markets the loads are usually relatively inelastic, meaning that they do not change as much as the price changes. When this is the case, the OPF objective is to minimize total generation cost subject to all relevant constraints. In MATPOWER it is possible to specify the inelastic power demand at a bus. The current version of MATPOWER cannot take elastic demand into account, but in principle this should be possible to do in the future. To model this, the coefficients in the cost function should be negative, because the load pays for the energy. A typical elastic demand function is decreasing with increasing price (e.g. $p = a - b \cdot P_G$ is a typical demand function, p is price). There should also be an additional constraint keeping the power factor[87] constant.

A full AC OPF is used in this chapter. For a detailed mathematical formulation of the OPF the reader is referred to Zimmerman and Gan (1997) and Christie et al. (2000).

6.2.2 The Lagrange multipliers and transmission congestion

Any optimization problem will have a Lagrange multiplier λ associated with each constraint in the problem. In our case, the Lagrange multiplier is the marginal value of the power balance constraint; the instantaneous price of the next small increment of load. If no interfaces are congested, then the zone price for all zones will be equal in the DC case (no losses) and almost equal in the AC case. The small difference is due to the effects of transmission losses.

In the uncongested case, an increase in a zone load may be met by an increase in output by a generator in that zone or by an increase in generation in another zone or zones. The generators with the lowest costs and which are not at their maximum output are dispatched first.

When congestion occurs, zone prices across the system are different. Then the higher cost generators within the same zone have to run, because a contingency or transmission line makes the lowest cost generators in others zones unable to supply load.

6.2.3 Optimal power flow used in a deregulated power system

Generators send a cost function and loads send a bid function to the ISO. The ISO has a complete transmission system model and can then do an OPF calculation. The zone prices determined by the OPF are used in the following way:

- Generators are paid the zone price for energy
- Loads must pay the zone price for energy

If there is no congestion and the ISO has run a DC OPF, there is one zone price throughout the whole system. Both generators and loads pay the same price for their energy. When there is congestion, zone prices differ, and each generator is paid its price in the zone and each load pays its price in the zone for energy.

[87] The cosine of the phase angle between the voltage and current.

If there are no losses in the transmission system then some interesting relations can be shown to be true:

$$\sum_{\text{all zones } i} \lambda_i \cdot P_{L_i} = \sum_{\text{all zones } i} \lambda_i \cdot P_{G_i} \tag{6.2}$$

where λ_i is the price in zone *i*. This implies that the ISO has to pay all the money it collects from the loads to the generators. However, when there is congestion there will always be a surplus. The money paid by the loads is greater than the money paid to the generators:

$$\sum_{\text{all zones } i} \lambda_i \cdot P_{L_i} > \sum_{\text{all zones } i} \lambda_i \cdot P_{G_i} \tag{6.3}$$

The OPF performs the function of controlling the transmission flows and thereby system security. Congestion will give rise to different zone (nodal) prices and the ISO collects a surplus. In the AC OPF there will be a surplus to the ISO in the case with no congestion (e.g. the left-hand term is greater than the right-hand term in Equation (6.2)).

6.3 The three test cases

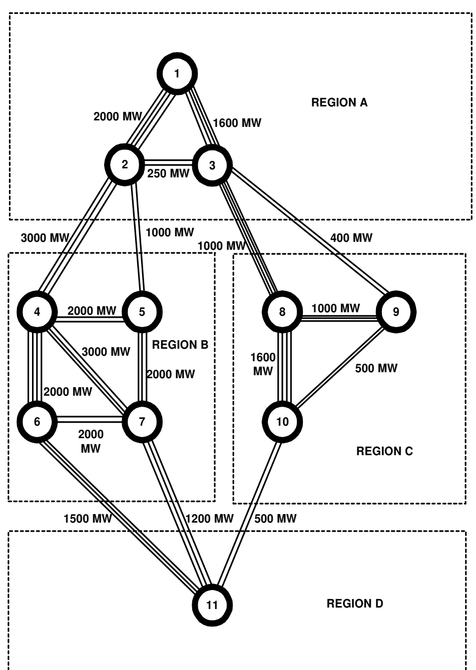

Figure 6-1. An eleven-zone model (Christie et al., 2000)

We use an eleven-zone power system from Christie et al. (2000) to illustrate the aspects of nodal pricing and congestion, shown in Figure 6-1. Each zone consists of a single bus. The zones are connected by interfaces. Each interface consists of multiple identical transmission lines.

Individual lines can be out of service, one at a time, and this event is called a contingency. When a contingency occurs, the power flow increases in the remaining lines in the interface and on lines in other interfaces. Flow limits immediately after a contingency are usually higher than in normal operation. Operators are expected to be able to reduce flows to normal limits before line damages occur. To reflect this common practice, post-contingency interface limits are 10% higher than normal interface flow limits.

Table 6-1. Generation and load cost data.

Bid Number	Zone	*b* Constant	*c* Constant	Max MW
1	1	10.00	0.0040	1000.0
2	2	15.00	0.0060	800.0
3	3	50.00	0.0080	1500.0
4	4	12.00	0.0050	2500.0
5	5	15.50	0.0060	1500.0
6	6	15.50	0.0070	1500.0
7	7	21.50	0.0080	1500.0
8	8	16.00	0.0060	1500.0
9	9	14.00	0.0050	1500.0
10	10	13.00	0.0040	1500.0
11	11	16.00	0.0060	700.0
12	11	31.00	0.0090	2000.0
13	1	-200.00	0.0000	1000.0
14	2	-200.00	0.0000	1000.0
15	3	-200.00	0.0000	1000.0
16	4	-200.00	0.0000	1000.0
17	5	-200.00	0.0000	1000.0
18	6	-200.00	0.0000	1000.0
19	7	-200.00	0.0000	1000.0
20	8	-200.00	0.0000	1000.0
21	9	-200.00	0.0000	1000.0
22	10	-200.00	0.0000	1000.0
23	11	-200.00	0.0000	1500.0

6.3.1 Base case

Table 6-1 shows the generation and load cost data (i.e. the *b* and *c* constants). Note that the value of the *a* constant does not affect the optimal solution which is well-known from optimization theory. It is set to zero in the calculations used in this Chapter. The loads are 1000 MW for all zones except zone 11 which has a load of 1500 MW. The willingness-to-pay (the negative *b* constant) is 200 EUR/MWh for all zones.

The data for transmission lines can be found in Table 6-2. In the base case, the transmission system is as shown in Figure 6-1. Contingencies are checked but no contingencies are binding at the optimal solution reached by the OPF. Table 6-3 and Table 6-4 show the base case OPF generation and load results, the zone lambdas and total export or import (positive values indicate export and negative values import).

Bus 11 has two generators, and in MATPOWER this is modeled by an introduction of a dummy bus for the most expensive generator. The transmission line connecting it to bus 11 has almost zero impedance and large transmission capacity.

All load is being supplied and all the generators are supplying some power with the exception of the generator in zone 3 and the second generator in zone 11 which are so expensive that they are not used. Note that any generator not at its minimum or maximum will have the same incremental cost in a DC OPF (almost the same incremental cost in the AC OPF).

Table 6-2. Example transmission system data.

From Zone	To Zone	No. of Circuits	Total Circuit Reactance *R*, per unit	Total Circuit Reactance *X*, per unit	Capacity in MW
1	2	4	0005	0.008	2000.0
1	3	4	0.010	0.012	1600.0
2	3	2	0.020	0.032	250.0
2	4	3	0.003	0.004	3000.0
2	5	2	0.005	0.008	1000.0
3	8	4	0.010	0.016	1000.0
3	9	2	0.015	0.020	400.0
4	5	2	0.003	0.004	2000.0
4	6	4	0.010	0.008	2000.0
4	7	3	0.003	0.004	3000.0
5	7	3	0.005	0.008	2000.0
6	7	2	0.0075	0.008	2000.0
8	10	4	0.010	0.012	1600.0
8	9	3	0.010	0.012	1000.0
9	10	2	0.010	0.016	500.0
6	11	3	0.0075	0.008	1500.0
7	11	3	0.010	0.012	1200.0
10	11	2	0.010	0.016	500.0

In the base case all zones have almost the same zone price (λ). Note that zone 11 is importing 800 MW of power, its first generator is at its maximum output of 700 MW and its second generator is not producing.

Table 6-3. Base case generation OPF results.

Bid Number	Bid Zone	Max MW	MW Sold	Generator Incremental Cost
1	1	1000.0	1000	18.00
2	2	800.0	800	24.60
3	3	0	0	50.00
4	4	2500.0	1865.2	30.65
5	5	1500.0	1263.8	30.67
6	6	1500.0	1085.4	30.70
7	7	1500.0	576.6	30.73
8	8	1500.0	1217.3	30.61
9	9	1500.0	1500	29.00
10	10	1500.0	1500	25.00
11	11	700.0	700	24.40
12	11	2000.0	0.0	31.00

In the uncongested case, the transmission system can withstand any first contingency outage of a single line in any interface and still not be overloaded. Total generation is slightly higher than total consumption, due to grid losses. The difference between total generation and load equals total grid losses.

Table 6-4. Base case load, zone lambdas and export/import.

Zone Number	Variable Generation	Variable Load	Zone Lambda	Total Export or Import
1	1000	1000	30.76	0
2	800	1000	30.71	-200
3	0	1000	30.85	-1000
4	1865.2	1000	30.65	865.2
5	1263.8	1000	30.67	263.8
6	1085.4	1000	30.70	85.4
7	576.6	1000	30.72	-423.4
8	1217.3	1000	30.61	217.3
9	1500	1000	30.54	500
10	1500	1000	30.57	500
11	700	1500	30.87	-800
Total	11508.3	11500		

6.3.2 Congested case

In this case congestion is created by changing the transmission system topology. All lines in the interfaces between zones 6 and 11 and zones 7 and 11 have been completely outaged. Table 6-5 shows the resulting congested system export/import data.

The active or binding constraint is a contingency of one line in the zone 10 to zone 11 interface which brings the remaining line in that interface to its post-contingency flow limit. This transmission limit is found by the calculation, 500 MW – 250 MW + 250 MW · 10% = 275 MW (data for the line from 10 to 11 are found in Table 6-2).

Table 6-5. Congested case export/import.

Zone Number	Variable Generation	Variable Load	Zone Lambda	Total Export or Import
1	1000.0	1000	29.47	0.0
2	800.0	1000	29.44	-200.0
3	0.0	1000	29.53	-1000.0
4	1738.6	1000	29.39	738.6
5	1158.5	1000	29.40	158.5
6	994.4	1000	29.42	-5.6
7	496.5	1000	29.44	-503.5
8	1095.0	1000	29.14	95.0
9	1497.8	1000	28.98	497.8
10	1500.0	1000	29.00	500.0
11	1225.8	1500	40.47	-274.2
Totals	11506.6	11500.0		

The congestion results in an import reduction into zone 11 from 800 MW in the base case to 274.2 MW. Therefore, generation in zone 11 must increase from 700 MW to 1225.8 MW to supply zone 11 load, and this must all come from the very high priced second generator in zone 11. The reduction of 525.8 MW in generation exported from the remaining zones results in their zone lambdas dropping slightly to around 29 EUR/MWh while zone 11 experiences an increase to 40.47 EUR/MWh due to the expensive second generator.

6.3.3 Congestion in a networked system

When congestion occurs on the radial interface in the previous case, there are two different zone prices at each side of the interface. Congestion in an interface that is part of a networked (meshed or looped) system will give unique zone prices at every bus. Congestion on any interface in a networked system affects zone prices in the entire networked system. This effect is illustrated by restoring the interface from zone 7 to zone 11 to service. Only the interface from zone 6 to zone 11 is out of service. Table 6-6 shows the AC OPF results.

Because of the increased interface capacity to zone 11, more power is imported and the more expensive generator in zone 11 now operates at 872.0 MW. This is a reduction of 353.8 MW from the previous case and lowers the zone 11 price.

The interface from zone 10 to zone 11 is still the binding constraint, but this interface is now part of a networked system with unique zone prices. Every time the load or generation changes in a zone it affects the flow on the congested interface, even when the changed load or generation is in a zone far from that interface. Higher zone prices appear where decreases in generation or increases in load increase the flow on the congested interface. Lower zone prices appear where increases in load or decreases in generation decrease the flow on the congested interface.

Table 6-6. Congestion in a networked system.

Zone Number	Variable Generation	Variable Load	Zone Lambda	Total Export or Import
1	1000.0	1000	30.3	0.0
2	800.0	1000	30.9	-200.0
3	0.0	1000	29.2	-1000.0
4	1929.4	1000	31.3	929.4
5	1316.2	1000	31.3	316.2
6	1143.2	1000	31.5	143.2
7	640.8	1000	31.8	-359.2
8	962.4	1000	27.5	-37.6
9	1345.2	1000	27.5	345.2
10	1500.0	1000	26.3	500.0
11	872.0	1500	34.1	-628.0
Totals	11509.2	11500.0		

6.4 Economics and transmission congestion

In economics, the ideal is a perfectly competitive environment, where goods wanted by consumers are produced at the least possible cost. In electricity markets, this would imply that consumers could buy power at the same price without respect to location.

However, a congested transmission system prohibits customers from buying power from lower cost generators. This implies that transmission congestion introduces inefficiency in electricity markets.

The degree of efficiency is measured by the social welfare, which should be maximized. The social welfare is the sum of the producer and consumer surplus, or alternatively the sum of the generator costs and the consumer benefits. The competitive benchmark is marginal cost pricing, resulting in maximum social welfare.

In a competitive market, more goods are produced at a lower price than in any other form of market.

To study what the topology of a congested network involves, the three test cases were analyzed with respect to the social welfare and the income (or congestion rent) to the ISO. The results are shown in Table 6-7.

Table 6-7. Economic analysis of the networks (CC = congested case and CNS congestion in a network system).

Network	Import/ Export (MW)	Income to the ISO (EUR)
Base case	-2423.4/2431.7	257
CC	-1983.3/1989.9	3441
CNS	-2224.8/2234.0	3110

Network	Generator Surplus (EUR)	Consumer Surplus (EUR)	Social Welfare (EUR)
Base case	110654	1946515	2057569
CC	105338	1946085	2051423
CNS	102234	1951250	2053484

The base case gives the highest social welfare, followed by the CNS case. As expected social welfare decreases as the number of line outages increases. When lines 6-7 and 7-11 are out of service (case CC) there is less export/import, and some of the high cost generators have to be scheduled, which increases the cost.

The income to the ISO is highest for the CC case and is lowest in the base case. The income to the generators (producer surplus) is highest in the base case, followed by the CC case. The consumer surplus is highest in the CNS case, followed by the base case. We also see that there is 8.3 MW net generation (export less import) in the base case, due to grid losses.

Another interesting aspect is how large the capacity of the congested interface should be before the price would be equal at both sides (i.e. to uncongest the interface). For the congested case, we found that the interface between 10 and 11 had to be 786 MW for the prices to be equal. This is an increase of 511 MW in capacity or 186 per cent. For the meshed network, the interface had to be 489 MW, which is an increase of 214 MW or 78 per cent. In the congested case, the price differential is 11.47 EUR/MWh between buses 10 and 11. To make investments in transmission lines profitable for producers at bus 10 their benefits from the line must outweigh investment costs.

The greatest price difference over an interface appeared between buses 10 and 11, with bus 11 as the higher price bus. The producer and consumer surplus is calculated in Table 6-8. The producers at bus 11 experienced higher profits and consumers received lower surplus during congestion. The potential for creation of transmission congestion and thereby exploitation of market power is therefore considerable at bus 11.

Table 6-8. Economic consequences for the players in the market at bus 11 for the three cases.

Network	Producer Surplus (EUR)	Consumer Surplus (EUR)
Base case	7469	253695
CC	16680	239295
CNS	9997	248850

To model market splitting[88] it is possible to compare the power flows from the unconstrained solution (i.e. the base case) with the interface limits defining the price areas, taking into account contingencies and security limits. When the unconstrained transfer exceeds the transmission limits, each price area becomes a separate market with the constraint that the power flow from one area to another does not violate the interface limit. In the case of two areas the power balance constraint for area A (the surplus area) states that the generation in area A is equal to load in area A plus maximum transfer from area A to area B (the constrained area). Similarly, the area B constraint states that generation in area B is equal to load in area B minus the maximum transfer from area A to area B. New transmission capacity constraints expressing the maximum transfers are then replacing the unconstrained transmission limits. In practice price areas are defined pragmatically, based on operational and engineering experience. Analytical determination of price area divisions in a meshed network is still an unresolved issue (Bjørndal and Jørnsten, 2001).

The Norwegian transmission provider (i.e. Statnett) can also use the OPF to analyze the impacts from new transmission lines or outages.

6.5 Conclusions

This chapter demonstrated how MATPOWER calculates the nodal prices as a result of an optimization of the minimum costs of active generation, taking into account the relevant constraints. Three cases were considered: a base case, a congested case and a congested case in a meshed network. We found that when we had a congested case with two interfaces out of service it gave rise to a significantly higher price in one of the nodes. When one interface was out of service and the network was meshed it gave rise to different nodal prices at every node. Some of the prices were higher or some were lower than in the uncongested case. The social welfare, producer and consumer surplus, and income to the ISO were calculated for the different networks. Congestion in a network decreased social welfare and created inefficiency.

We also found how much we had to increase the capacity in the lines to uncongest an interface. Bus 11 was found to be a market where market power potentially could be exploited because the generators received higher profits under congestion.

[88] Strictly speaking, the relationship between the nodal prices and area prices in Norway is; nodal price = Area price • factor, where the factor is the adjustment for marginal losses in the grid.

Finally, it was shown how Nord Pool and Statnett could use OPF to analyze price areas and transmission congestion, including aspects of security and reliability.

7 Pricing of Contracts for Differences in the Nordic market

The purpose of this chapter is to give an introduction to, and a pricing analysis of Contracts for Differences (CfD), introduced on November 17, 2000 at Nord Pool. The CfD is a forward market product with reference to the difference between the future seasonal area price and System Price. By using available historical trading prices and spot prices for seven seasonal contracts and one yearly contract, it is possible to analyze the relationships between the contract prices and the value of the underlying asset. For the first seven seasonal contracts it appears that the CfDs traded at Nord Pool are mostly over-priced relative to the underlying asset. Pricing theory for forward contracts explains this by the presence of a majority of risk-averse consumers who are willing to pay a risk premium for receiving the future price differential. We utilize statistical analysis with regard to the contract prices and the underlying asset, and find some interesting relationships. The analysis is preliminary because the CfD market is relatively new.

7.1 Introduction

In many electricity markets there is now a demand for new risk management tools. The Nordic market has shown a growing concern for transmission congestion and the associated risks of Area/System Price differentials. As a result, Contracts for Differences (CfDs) were introduced at Nord Pool November 17, 2000. These financial instruments make it possible for the players in the market to hedge against the difference between the area price and the System Price in a future time period. The forward and future contracts traded at Nord Pool are referred to the System Price, while the generators are being paid the area price in their area for their production, and the consumers purchase electricity at the area price referring to their area. Often the generators and consumers are located in different areas, facing periods with transmission congestion and area prices that differ from the System Price. They may therefore be exposed to significant financial risks.

One extension of CfDs is financial transmission rights (FTRs) (Hogan, 1992). The FTR concept has been developed by Professor William W. Hogan at Harvard University (Hogan, 2004). FTRs can be used to hedge directly against a locational price difference, and they have been used in the PJM Interconnection (Pennsylvania, New Jersey and Maryland) since April 1998, and in New York since 1999. A study of how well the markets for hedging transmission congestion function is important because it will have implications for implementation in other regions.

This chapter describes the Nordic electricity market, Nordic transmission pricing, and congestion management procedures. We study CfDs in an advanced electricity market. We discuss general theory for pricing of forward contracts, and the principles of CfDs. Utilizing data from November 17, 2000 to April 30, 2003, the CfD prices are analyzed with regard to the value of the underlying asset and volatility. Since the market for CfDs is relatively new, the limited data available might be insufficient to draw fully conclusive results.

7.2 The Nordic power market

Since January 1996, Norway and Sweden have had a common electricity market, with Finland joining in September 1998, followed by western Denmark in January 1999 and eastern Denmark in October 2000. These areas now constitute a common Nordic market.

In the Nordic region Nord Pool organizes two different markets for electricity, ***Elspot*** and ***Eltermin***. In the Elspot market, buyers and sellers trade in a daily spot market concluded at the day-ahead stage. Traders can submit offers to sell or bids to buy the physical electricity they expect to produce or consume for every hour of the next day. The System Price (spot price) is determined by the intersection point of the aggregated purchase (demand) and sale (supply) curves. The System Price is the price independent of any transmission constraints (i.e. the unconstrained price), and is the spot price for the common Nordic[89] market.

The Eltermin market is purely financial and is divided into the *futures* and *forwards* markets. These are markets for cash settlement of a specified volume of power at an agreed upon price, date and period. The market participants may trade for delivery up to four years in advance. Futures and forward contracts are used for trading and risk management. The main difference between the futures and forward contracts is the daily marking to market and settlement of futures contracts. Forward contracts are settled when the contracts reach their due dates. Forward contracts, which are the relevant contracts in this case, have 3 seasonal delivery periods: Winter 1 (weeks 1-16), Summer (weeks 17-40), and Winter 2 (weeks 41-52/53). The forward contracts can also be purchased as yearly contracts. The System Price is used as a reference price for the forward and futures contracts. It is also used as the reference price for the Nordic over-the-counter (OTC) market, which is a bilateral wholesale market. Due to possible differences between the System Price and the actual area price of the sales or purchases, this hedging mechanism is imperfect. To overcome this price differential risk, CfDs were introduced.

The futures contracts can be purchased as day, week or block contracts. The spectrum of contracts is updated dynamically every day. The week contracts are split into day contracts seven days before the delivery period starts, while the block contracts are split into week contracts four weeks before the delivery period starts. The new block contracts are issued one year before delivery. The time horizon for futures contracts is 8-12 months.[90]

Besides the Nord Pool markets there is a bilateral market for OTC contracts. In this market the most common contract types are forward contracts with different (fixed)

[89] Currently the System Price is the price cross between total bids and offers in Norway, Sweden and Finland. Bids/offers in the Danish areas are also included in the calculation up to the capacity limits to or from these areas. Beginning January 2006 the System Price will include Denmark West and Denmark East.

[90] From the fall of 2003 several changes in Nord Pool's financial market product structure will take place. The block contracts will be replaced with month contracts. The block and week contracts will be listed as 6 and 8 consecutive contracts in a continuously rolling cycle respectively. The year contract 2006 will be cascaded into quarters.

load profiles, options and forward contracts with flexibility in the load profile (load factor contracts).

The balancing market at Nord Pool is called Elbas. In this market the players can trade one-hour contracts until one hour before real time. It is currently only available in Sweden and Finland. Deviations from generation and supply in the spot and the Elbas markets are managed by trading in the real-time market operated by the transmission system operators (TSOs). The TSOs in the Nordic countries apply different rules for the calculation of the real-time prices and the clearing of the market.

The electricity is generated from different energy sources in the Nordic countries. Norway uses 99% hydropower, while Sweden has a mix of hydropower (mainly located in the north), nuclear power and conventional thermal power (located in the south). Denmark has mainly thermal power generation (89%), with an increasing share of wind power (11%). Finland has the same mix of generation as Sweden, but with a higher share of thermal and nuclear power than hydropower. Due to the high share of hydropower in the Nordic system, production can vary from a dry to a wet year with an order of magnitude of 40 TWh. The hydropower production is easily regulated, and can show substantial differences during the day. For this reason the transmission requirements can vary greatly. There is also a considerable load growth in the Nordic area (1.55% pa. during the 1990s). On cold winter days with high peak-load, the system can be capacity constrained, resulting in hours with high prices (up to 1500 NOK/MWh). For more information on the Nordic power market, see Nord Pool (2002a, 2002b and 2002c).

7.3 Transmission pricing and congestion management

The ideal tariff for trading arrangements in deregulated markets should have the following properties:

- Market players should know their locational transmission cost.
- The transmission costs should be independent of the location of the trading counterpart.

Below we describe the main features of Nordic transmission pricing.

7.3.1 Nordic transmission pricing

The point-of-connection tariff is used in transmission pricing in the Nordic region. The Nordic tariffs give full access to the Norwegian, Swedish, Danish and Finnish markets. The tariffs have substantial differences, but it is possible to accomplish market transactions across national borders of connection, because of the properties of the point tariff. An essential property of this tariff is that it should not be an obstacle to free trade or restrict a player's ability to choose counterparties (third party access - TPA). During the transition period, prior to a common Nordic market, border tariffs have been charged. The tariffs have been volume-dependent and have been based mainly on reciprocity, to make the competition fair on both sides of a border.

The rates for injections into and withdrawals from the grid are different. The geographic location within the transmission grid also affects the rates. Cumulative tariffs require that the players pay the sum of the tariffs levied, including the high-voltage national network, down to lower-voltage local distribution grids. The main principles of the cumulative tariff rates are:

- Main-grid tariffs must fairly reflect the main grid's total costs.
- Regional-grid tariffs must fairly reflect total regional-grid costs, plus utilization of the main grid.
- Local-grid tariffs must fairly reflect local-grid costs, plus utilization of the regional grid.

Main-grid tariffs are complex since they include several cost components. Local-grid tariffs can be simple, including only an annual connection fee and a volume-dependent fee.

Losses in the Nordic grid are treated as TSO consumption. The TSOs have to purchase grid losses in the spot market or from the bilateral contract market. The associated costs are recovered through the transmission tariff.

7.3.2 Market splitting, counter trade and constrained export/import

When congestion is predicted, two or more spot areas are defined. This procedure is called market splitting. It is used within Norway and at the border interconnections among the Nordic countries. In these cases the players must specify their bids in the different spot price areas. By the clearing at Nord Pool the prices in the different areas are decided such that the power flow does not exceed the specified constraints. A surplus area will then receive a lower price than a deficit area. The difference between the respective area prices and the System Price is called the Congestion Fee.[91] Market splitting gives price signals to the market players when there is scarcity of transmission capacity. The TSO receives an income from the market splitting, and therefore may have no incentives for expanding the grid.[92]

Statnett (the Norwegian system operator) defines the fixed price areas in Norway according to its information on the likely pattern of flows on the system for a certain period of time. The price areas are named as NO1 and NO2. When necessary, additional price areas may be utilized. Sweden (SE) and Finland (FI) constitute one price area each, Denmark two (west DK1 and east DK2), and Norway constitutes two or three areas. In total there are six to eight (depending on the number of areas in Norway) price areas in the Nordic region. Congestion inside the price areas is managed by counter trade. Congestion between the countries can also be handled by constrained import/export. The bottleneck west of Oslo is managed by restriction of export to Sweden. In Sweden, Jutland, Funen, and Zealand there is counter trade after a restriction of import/export is conducted. In Finland there is only counter trade with an exception for unexpected events. Among all countries counter trade occurs when the real time physical flow is approaching the maximum transmission limit.

The bids in the balancing market are first meant to balance the power system

[91] Statnett (the Norwegian system operator) uses the term “Capacity Fee” (Norwegian: kapasitetsavgift).

[92] To what extent the system operator keeps the congestion rent depends on the economic regulation of the grid company. With the current regulation in Norway (revenue cap regulation) the congestion rent adds nothing to the net revenue of the system operator.

(frequency control), but because they contain geographical information they can be used to manage congestion. If the power flow through a bottleneck exceeds the allowed limit, the TSO orders increased production (upward regulation) within the constrained area and decreased production (downward regulation) in the surplus area. This is counter trade, and it involves an expense for the TSO. The price paid for increased production is always higher than or equal to the System Price, while the price for decreased production is lower or equal. Downward and upward regulation is rewarded with the difference between the System Price and the price in the real-time market. The increased production (or decreased consumption) must occur in the area with the more expensive production, and the decreased production (or increased consumption) must occur in the area with cheaper production. The costs associated with counter trade over time can give the TSO incentives to expand the grid, and thereby reduce the costs. The counter trade gives one market with a uniform price, which promotes electricity trade. If the price differences are not allowed to last for some time, an extended utilization of counter trade can interfere with the price signals from scarcity of transmission capacity.

It is important to distinguish between a thermal generator and a hydropower generator with regulation ability when transmission congestion is analyzed. Water can be stored and used later for production. When a bottleneck is predicted and has a certain period of duration, the congestion management methods have different impacts on the use of water. Spillage involves lost energy production and local low prices, if market splitting is used. The generators will earn more money by producing more before the bottleneck settles. With counter trade the generators can adjust as though there is no congestion. In a situation where the export capacity from an area is constrained, the generators are paid the System Price for their production. In addition they can participate in the counter trade arrangement. They avoid low area prices at the same time they are being paid for the water not produced because of transmission constraints. This weakens the incentives for avoiding spillage.

7.3.3 Historical area price differences

The Norwegian Water Resources and Energy Directorate (NVE), which is the grid company regulator in Norway, believes that market splitting is the most efficient method to handle planned and persistent bottlenecks due to the grid's structure and the varying reservoir levels (Norwegian Competition Authority, 2000). Small temporary bottlenecks due to failures, outages, and maintenance of the network are better handled by a counter trade arrangement.

Since January 2000, NVE has introduced a test scheme with fixed price areas. The division of the areas will be reassessed before each season and will be fixed thereafter. Within the areas, congestion will be managed by a counter trade arrangement unless the costs associated with one bottleneck are higher than a specified cost.

Table 7-1.Average yearly area prices (NOK/MWh) for 1996-2002.

Year	System Price	Oslo (NO1)	Tromsø (NO2)	Stockholm (SE)
1996	253.74	256.79	251.40	250.80
1997	135.28	137.77	133.24	133.23
1998	116.92	116.48	116.75	114.75
1999	111.97	109.00	119.43	113.06
2000	103.21	97.55	100.56	115.38
2001	186.49	185.95	188.55	184.16
2002	200.98	198.45	200.12	206.27

Year	Helsinki (FI)	Copenhagen (DK2)	Århus (DK1)
1998	116.76		
1999	113.64		122.44
2000	120.61	138.03	133.20
2001	183.98	189.72	191.21
2002	203.82	213.68	190.74

Table 7-1 shows the yearly average prices for 1996-2002. As can be seen, the Stockholm, Helsinki and Copenhagen prices for 2001 were below the System Price. The Oslo price has on average been below the System Price since 1998. Conversely, the Århus (except 2002) and Copenhagen prices have been above the System Price since 1999 and 2000 respectively. This has implications for the electricity trading among the Nordic countries. For example, a trade of 100 GWh between two locations with a price differential of 5.26 NOK/MWh implies a Congestion Fee of NOK 526100.

Table 7-2 shows the percentage of the years in which the area price differed from the other area prices. Historically there has been a substantial percentage of the year with price differences, especially for the NO1, NO2 and DK1 areas.

Table 7-2. Percentage of the years in which the area price differed from all other area prices.

Year	Oslo (NO1)	Tromsø (NO2)	Stockholm (SE)	Helsinki (FI)
1998	22.9%	23.1%	3.2%	
1999	33.2%	36.6%	0.6%	4.0%
2000	55.0%	41.7%	5.5%	15.8%
2001	8.9%	23.8%	0%	0.9%

Year	Copenhagen (DK2)	Århus (DK1)
1999		33.8%
2000	7.2%	44.8%
2001	5.4%	19.1%

7.4 Forward pricing theory

It is possible to use two different theories for pricing of forward and futures contracts (Fama and French, 1987). The first theory describes the current forward price as the expected spot price, plus a cost of storage and minus a convenience yield. The second theory states that the forward price is equal to the expected future spot price discounted at the risk premium for the holding period. Both of these theories are discussed as well as how they can be used for pricing of electricity forward and futures contracts. Our discussion is based on the references Botterud et al. (2002), Clewlow and Strickland (2000), Leong (1997), Pindyck (2001) and Schwartz (1997). Let us briefly discuss risk premiums in pricing of commodities after presenting both theories.

The traditional financial markets use the no arbitrage models for the valuation of the forward prices. The models show a relationship between the spot and forward prices by the possibility of arbitrage between the prices. Since it is easy to buy and sell the underlying asset, the argument of no arbitrage can be used.

However, in electricity markets, the no arbitrage models are not useful because they depend on whether a commodity can be stored. This is the opposite of storable commodities, where inventories play an important role in the price formation (Pindyck, 2001).

The cost of carry relationship states that the payoff to a forward sale of an asset can be replicated by borrowing money for the purchase in the cash market, holding the asset until maturity, and then delivering the asset into the long position, using the funds received to pay off the loan. This relationship holds in markets where arbitrageurs are able to purchase and short sell assets easily.

For some participants, holding the underlying asset has value relative to having the forward contract. The value has been termed the convenience yield. It can be represented in terms of an effective continuous dividend stream δ which the holder of the spot asset receives. The convenience yield also reflects the market's expectation about the future availability of a contract.

Let $F(t,s)$ be the price of a forward contract at time t and with maturity time s (i.e. the life of the forward position is $s\text{-}t$) on a spot asset that is currently trading at the price $S(t)$. Taking into account the cost of carry relationship and the convenience yield, the pricing formula for a forward is:

$$F(t,s) = S(t) \cdot e^{(r+w-\delta)(s-t)} \qquad (7.1)$$

where r is the financing cost assuming continuous compounding over the life of the forward position, $s\text{-}t$, and w represents the cost of storage over the holding period.

This formula can determine some interesting relationships between the spot and the forward prices. Depending on the relative magnitude of the interest rate (positive), the cost of the storage (positive) and convenience yield (negative) the forward price will be less, equal to, or greater than the expected future spot price. The forward curve is said to be in contango when the forward price is greater than the expected future spot price implying an upward sloping (normal contango) forward curve as illustrated in Figure 7-1. When the forward curve is downward sloping (normal backwardation) the forward price is less than the expected future spot price.

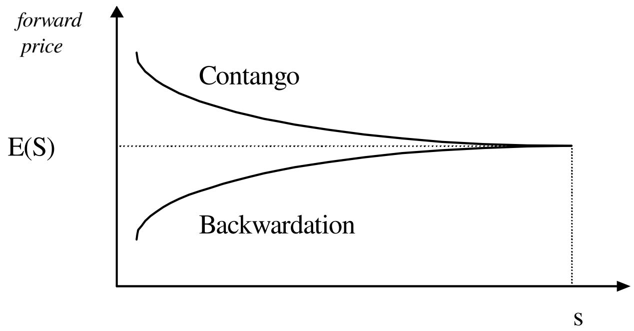

Figure 7-1. Illustration of normal contango and backwardation in the forward market.

Often it is impossible to sell the underlying asset short and thereby execute arbitrage. In the presence of backwardation the market players should buy the forward contract at a discount to the spot price.

The electricity storage problem implies non-uniqueness of forward prices, which means that the market is incomplete. The characteristics of incomplete markets are heavy tails, autocorrelation, skewness and illiquidity.

The second theory for pricing of forward contracts takes into account an investor's risk preference. The price of a forward contract is equal to the expected (*E*) future spot price and discounted at the risk premium at the time *s*. The commodity risk premium, $v = -(r - f)$, is equal to the difference between the investor's discount rate f and the risk-free interest rate r. The risk premium must be interpreted in the light of the risk preference and the market share of the supply and demand side. The theory states that a risk-averse investor would require a positive risk premium for a future investment, while the opposite holds true for a risk-seeking investor. The forward price can now be expressed as:

$$\begin{aligned} F(t,s) &= E(S(s)) \cdot e^{(r-f)(s-t)} \\ &= E(S(s)) \cdot e^{-v(s-t)} \end{aligned} \tag{7.2}$$

The forward-spot price relationship can be analyzed depending on the sign of v. A positive risk premium for a generator implies that the forward prices are lower than the expected future spot price. Conversely a negative risk premium for the consumer implies that the forward prices are greater than the expected future spot price. Several implications can be drawn, depending on the roles of the players (i.e. generators or consumers) and the dominance in the market. If the market player is a risk-averse generator it may want to hedge its production in the forward market. A market with dominant risk-averse generators will involve a forward market in backwardation. On the other hand, if the risk-averse consumers are the dominant players, this would imply a market in contango.

The risk premium can also be explained by considering the correlation between the forward price and the spot price. If the two prices are positively correlated this involves a positive systematic risk. Thus an investor would require an expected return above the risk-free interest rate.

A risk premium could arise if either the number of participants on the supply side differs substantially from the number on the demand side, or if the degree of risk averseness varies considerably between the two sides.

The share of generators and consumers in the forward market can be assumed to be relatively equal, since many companies have both generation and load. Concerning the capability of adjusting the quantity of supply and demand there are differences. The demand of electricity is relatively inelastic, while the generators have much more flexibility in regulating the produced quantity, especially the hydropower generators that can regulate their production in a short period of time. For these reasons the generators may not want to hedge their production in the forward market. The generators can use the available information to optimize their production in accordance with the hours with the highest prices in the day-ahead spot market and in the real-time market. On the other hand, if the consumers are risk-averse they may want to hedge their future consumption in the forward market by being willing to pay a risk premium for the future asset.

The sign of the risk premium can also be dependent on the supply and demand of forward contracts. If there is an excess supply of contracts this would imply a positive risk premium, while an excess demand would imply a negative risk premium.

In the context of a forward contract on the difference between the area price and the System Price, the risk premium theory will have the following interpretations. If the price differential in a given area is positive, the consumers are penalized if they have purchased a forward contract related to the System Price. They are risk-averse if they pay for the contract at a price greater than the expected price differential. If the price differential is negative, generators are penalized, and they are risk-averse if they pay for a contract that is more expensive than the expected price differential (in absolute value).

The CfD is settled against the difference between the area price and the System Price, while the forward contract itself is priced based on the market's expectations about the future spot prices. The risk premium model can then be formulated as:

$$\begin{aligned} CfD(t,s) &= E(AP(s)-SP(s))\cdot e^{(r-f)(s-t)} \\ &= E(AP(s)-SP(s))\cdot e^{-v(s-t)} \end{aligned} \tag{7.3}$$

where *AP(s)* and *SP(s)* are the future Area and the System Prices. The difference is that the expected spot price now is a difference which is typically more volatile than a single spot price. In general there will be different risk premiums for different areas. A hydropower area like Norway (in a normal or wet year) will have an area price which is lower than the System Price, implying a negative CfD price. Typically if the generators have sold most of their production as forward contracts referred to the System Price, they would be willing to pay a risk premium to hedge against the price differential. Conversely, in a thermal area the area price would be greater than the System Price (with a corresponding positive CfD price), and consumers would be willing to pay a risk premium since it has to purchase power at the local price.

If forward contracts referring to area prices in the Nordic market existed we would have the following relationship:

$$\begin{aligned} CfD(t,s) &= FAP(t,s) - FSP(t,s) \\ &= E(AP(s) - SP(s)) \cdot e^{-v(s-t)} \\ &= E(AP(s)) \cdot e^{-v1(s-t)} - E(SP(s)) \cdot e^{-v2(s-t)} \end{aligned} \tag{7.4}$$

where *FAP(t,s)* and *FSP(t,s)* are the Area and the System Price forward contracts at time *t* and maturity *s*, and *v1* and *v2* are the risk premiums of the respective prices. The above equality would be true due to a no-arbitrage argument.

All other things being equal, the longer the duration of a forward/futures contract or the more forward it can be purchased, the greater the hedging benefits it contains. Conversely, a very short-term contract has limited value, since its returns will closely approximate those of the underlying asset. The cost of this contract should be correspondingly small.

Electricity markets generally exhibit complicated seasonal patterns. A peak is observed in winter due to the demand for heating. The spot price will also depend on the inflow to the reservoirs. There can be daily and hourly patterns, with less price variations in hydropower-dominant areas due to the high degree of controlling ability. The more complicated patterns are due to the non-storability of electricity. Another factor is that the electricity market is still a regional market. Differences among regions arise due to the fuels used to produce electricity, weather patterns, demographics, local supply and demand conditions, etc. Transmission lines between different regions help to reduce such problems but constraints on the lines mean that the problems do not completely disappear.

The markets for oil, gas and coal will be related to the electricity markets since these are used as fuel in thermal power plants. Empirical research by Pindyck (2001), Fama and French (1987), Bodie and Rosansky (1980) and Chang (1985) on commodities futures prices finds evidence to support normal backwardation for petroleum and agricultural products and portfolios of commodities. The risk premium may vary in time, but is not related to the general level of the stock market.

7.5 Major issues in trading forward and futures contracts

Forward and futures contracts are a means of transferring risk to those who are able and willing to bear it and allow investors to transfer risk to others who might profit. The party transferring risk achieves price certainty but loses the opportunity to make additional profits. The party taking on the risk loses if the counterparty's downside is realized. Except for transactions costs, the winner's gains are equal to the loser's losses.

According to Khoury (1984) a hedger is primarily motivated by the security and not the profit derived from the futures transaction. A speculator on the other hand, is motivated by the profits that are achieved through the successful prediction of price movements in a futures transaction. An arbitrageur capitalizes on unjustifiable price differences (e.g. between two different markets) over space or over time (e.g. between one maturity month and another). Pure arbitrage involves zero risk and no commitment of capital. The activities of the agents will determine the futures prices.

The basis is the differential at a point in time between the futures price of a commodity and the spot price of the same commodity. Futures prices often exceed spot prices, but not always. The closer the spot price is to the higher futures price, the stronger the basis. A strong basis reflects excess demand for the commodity. In this case, the spot market is indicating its willingness to pay for earlier spot delivery. A weak basis indicates that the market is unwilling to make early "storage" payments.

Under uncertain conditions, speculators would buy or sell futures contracts, depending on whether their expectations about future prices coincide with the maturity of the contracts. If their expected price is greater than the futures price they would be long on the futures contract. Conversely a short position would be established if the expected price is less than the futures price. The hedgers would enter futures contracts to offset their current or expected cash position, independent of what the expected price is going to be. Hedgers are only interested in shifting the risk that results from price fluctuations onto the speculators. Those who make sure that the relationship between the futures price and spot price is in equilibrium are the arbitrageurs. Arbitrageurs tend to bet on more certain outcomes than on a forecast vs. a forward price. However, it would be easier to sell month m if it looks overvalued relative to m-1, because the bet can be hedged by buying m-1, and two prices one month apart can be expected to move together. It would be more difficult for a prudent trader to sell month m based on a forecast of spot prices in month m showing it is overvalued. If the traders own the option to build a power plant, that option is also a hedge that allows one to sell forward. Given the methods of traders and arbitrageurs, can we expect a consistent bias in the forward market?[93] This issue is worth examining.

7.6 Forward locational price differential products

The CfD is a forward market product with reference to the difference between the area price and System Price during the delivery (settlement) period.

CfD = average during the delivery period of
(daily area price – daily System Price) (7.5)

From this formula we see that every time the area price is higher than the System Price the holder receives a rebate equal to the price differential. Otherwise the holder must pay the difference in prices. The payoff from a CfD is determined by calculating Equation (7.5) during the settlement period and multiplying the price differential by the contracted volume. The price of these contracts is settled by the supply/demand

[93] Personal communication with power trader at Morgan Stanley, New York.

drives.

New forward area price contracts could also be introduced, but they would split the total liquidity among several products, and are therefore rejected.

The market price of a CfD during the trading period reflects the market's prediction of a price differential during the delivery period. The market price of a CfD may be positive, negative or zero. CfDs are traded at positive prices when the market expects the area price to be higher than the System Price (a net import situation). CfDs will trade at negative prices if the market expects an area price below the System Price (a net export situation).

A perfect hedge using forward or futures contracts is possible only when the area price and the System Price are equal. If forward or futures contracts are used for hedging there is a basis risk equal to the difference between the area price and the System Price. To create a perfect hedge against the price differential, a three-step process using CfDs must be used:

1. Hedge the specified volume by using forward contracts.
2. Hedge against the price differential – for the same period and volume – by using CfDs.
3. Accomplish physical procurement by trading in the Elspot area of the holder of the contract.

In the Nordic market the term Contract for Differences differs from the corresponding term used in the British market. In the Nordic region CfDs are used to hedge against the difference between the two uncertain prices (area price and System Price), not as in the British market, against the difference between the spot price and a pre-defined reference price or price profile. The Nordic CfD is a locational swap, while the British CfD is settled based on the difference between the spot price and the reference price.

CfDs are also cleared at Nord Pool through Nord Pool Clearing, and it is assumed that the OTC volume is higher than the volume provided by Nord Pool's financial market. The clearing service provided by Nord Pool reduces the counterparty and payment risk associated with the contracts. The fact that Nord Pool is providing the clearing service may therefore increase the liquidity of the contracts.

Table 7-3. Traded volumes of CfDs.

OTC volume (GWh)			
Reference area	**Winter 1 2001**	**Summer 2001**	**Winter 2 2001**
Århus (DK1)		**161.6 (4.5%)**	**541.2 (19.1%)**
Helsinki (FI)	**43.2 (7.3%)**	**918.0 (25.7%)**	**788.6 (27.0%)**
Oslo (NO1)	**28.8 (4.9%)**	**844.6 (23.7%)**	**1581.6 (38.3%)**
Stockholm (SE)	**518.2 (87.8%)**	**1645.1 (46.1%)**	**1115.5 (13.1%)**
Total	**590.2**	**3569.2**	**4126.4**
Number of trades	**7**	**48**	**62**

Table 7-3 shows the OTC volume traded for the first three trading periods. The number in brackets is the percentage of the total volume traded for each season. As expected, the volume traded is highest for the Winter 2 2001 contracts which have a longer trading period. The majority of the contracts traded are referred to Helsinki and Oslo. Most of the Winter 1 and Summer 2001 contracts are referred to Stockholm. No contracts referred to Copenhagen are traded OTC. The traded volume and the number of trades have increased during all trading periods, but more data are needed to reach a conclusion about liquidity. Accumulated volumes for the CfDs at Nord Pool were not reported on the exchange's Web page. The volume traded on Nord Pool's financial market is approximately one third of the total volume of cleared power, while the OTC volume constitutes the rest. Including the power cleared via Nord Pool, a total power volume of 2770 TWh was handled by the exchange in 2001. This is approximately seven times the yearly physical power delivery.

7.7 Pricing analysis

This section analyzes the prices of the contracts with the technical information in Table 7-4. The CfD referred to Eastern Denmark was introduced March 23, 2001. June 15, 2001 yearly contracts were introduced with a trading period extending to December 21, 2001.

Based on the available information from Nord Pool we analyzed how the CfDs were priced in the respective periods. The average traded prices and the standard deviations are calculated in Table 7-5.

The prices of Winter 1 2001 contracts are relatively stable with small standard deviation. The Århus contract has the highest prices and the Oslo contract the lowest prices (negative prices). This is in contrast to the prices of the Summer 2001 contracts which are relatively stable until the new year, when they decrease to a new level. The standard deviations for these contracts are relatively high and have the same order of magnitude as the contract prices. On average the Århus contract has the highest prices and the Oslo contract the lowest prices. The Winter 2 2001 contract prices start at a relatively high level and stabilize at a lower level in the spring and summer. The standard deviation for these contracts is of the same order of magnitude as the contract prices. On average the Helsinki contract has the highest prices while the Århus contract has the lowest prices. The prices of the Winter 1 2002 contracts, they start at a relatively low level and increase towards the end of the trading period. The standard deviation is as high as for the preceding contracts. On average the Copenhagen contract has the highest prices and the Århus contract the lowest prices. The next seasonal contract Summer 2002 has prices in line with the Summer 2001 contracts. The Copenhagen contract however has increased over 480% in price and the Århus contract has increased 33% in price. The standard deviation relative to the absolute value has decreased for all contracts except Oslo. The next seasonal contract Winter 2 2002 has prices that have increased (except Oslo) relative to Winter 2 2001. The Copenhagen contract especially shows a substantial increase. The standard deviation relative to the absolute value has decreased for all contracts. It is worth noting that the Århus contract has a high negative payoff.

Table 7-4. Product specification for the CfDs.

Product-series	Contract hours	Trading period	Settlement period
Århus (DK1), Helsinki (FI), Oslo (NO), Stockholm (SE) Winter 1 2001	**2879**	**17.11-29.12.2000**	**01.01-30.04.2001**
Århus (DK1), Copenhagen (DK2), Helsinki (FI), Oslo (NO), Stockholm (SE) Summer 2001	**3672**	**17.11.2000-30.04.2001**	**01.05-30.09.2001**
DK1, DK2, FI, NO, SE Winter 2 2001	**2209**	**02.01-28.09.2001**	**01.10-31.12.2001**
DK1, DK2, FI, NO, SE Winter 1 2002	**2879**	**02.05-28.12.2001**	**01.01-30.04.2002**
DK1, DK2, FI, NO, SE Summer 2002	**3672**	**01.10.2001-30.04.2002**	**01.05-30.09.2002**
DK1, DK2, FI, NO, SE Winter 2 2002	**2209**	**02.01-30.09.2002**	**01.10-31.12.2002**
DK1, DK2, FI, NO, SE Year 2002	**8760**	**15.06-21.12.2001**	**01.01-31.12.2002**
DK1, DK2, FI, NO, SE Winter 1 2003	**2879**	**02.05.-30.12.2001**	**01.01-30.04.2003**
DK1, DK2, FI, NO, SE Summer 2003	**3672**	**01.10.2002-30.04.2003**	**01.05-30.09.2003**

The prices for the year 2002 contracts show the same trend as the Winter 1 2002 contracts, with relatively low prices in the summer, and increases towards the end of the trading period. Generally the standard deviation for these contracts is less than the contract price itself, except for the Oslo contract. On average the Copenhagen contract has the highest prices and the Oslo contract the lowest prices.

During winter 2002-03 there were high electricity prices which could affect the market's expectation about transmission congestion. The data for the Winter 1 2003 contracts show that the prices for all contracts differ from the other Winter 1 contracts studied. We observe that the Århus contract has a high negative payoff and standard deviation. Data for the seasonal contracts Århus and Copenhagen Summer 2003[94] show a relative large decrease in price from the same season previous year. The other contracts show smaller changes and converge to a level around 2-4 NOK/MWh.

The willingness to pay is highest for the Århus contract Summer 2002 followed by Winter 1 and Summer 2001. The Summer 2002 Copenhagen and Winter 2 2002 contracts have the second highest willingness to pay. Conversely the lowest willingness to pay (negative) is for the Århus contract Winter 1 2003. It is also interesting that the Oslo contract has negative prices on average for all seasons in 2001 and 2002 and for the year 2002. This means that the buyers of these contracts are receiving money for holding these contracts, but they have an obligation to pay the difference between the Oslo price and the System Price if it is negative during the delivery period. In the seasons Winter 1 2003 and Summer 2003 the Oslo contract has positive prices reflecting the drought in Norway with high area price during the winter 2002-03.

[94] Spot price data for the season Summer 2003 was not available at Nord Pool, except on a daily basis.

Table 7-5. Data concerning the prices of the CfDs analyzed and the value of the underlying asset.

Winter 1 2001 (2879h)	Average traded price (NOK/MWh)	St. dev.	Average of (AP-SP)
Århus (DK1)	15.39	1.67	-4.55
Helsinki (FI)	10.44	0.61	-0.77
Oslo (NO1)	-4.56	0.48	-0.16
Stockholm (SE)	8.82	0.88	-0.19
Summer 2001 (3672h)	Average traded price (NOK/MWh)	St. dev.	Average of (AP-SP)
Århus (DK1)	15.09	14.69	9.05
Copenhagen (DK2)	3.08	1.41	-3.18
Helsinki (FI)	6.62	5.02	-7.07
Oslo (NO1)	-1.98	1.85	-0.25
Stockholm (SE)	3.61	4.02	-7.12
Winter 2 2001 (2209h)	Average traded price (NOK/MWh)	St. dev.	Average of (AP-SP)
Århus (DK1)	-1.57	4.21	7.85
Copenhagen (DK2)	1.92	1.54	11.69
Helsinki (FI)	2.05	1.60	-1.25
Oslo (NO1)	-0.67	0.83	-2.35
Stockholm (SE)	1.12	1.21	-1.25
Winter 1 2002 (2879h)	Average traded price (NOK/MWh)	St. dev.	Average of (AP-SP)
Århus (DK1)	-3.06	2.02	7.10
Copenhagen (DK2)	4.78	4.15	15.33
Helsinki (FI)	2.86	1.46	1.01
Oslo (NO1)	-0.30	0.45	-0.69
Stockholm (SE)	2.16	1.98	0.97
Summer 2002 (3672h)	Average traded price (NOK/MWh)	St. dev.	Average of (AP-SP)
Århus (DK1)	20.11	5.75	30.23
Copenhagen (DK2)	17.86	5.71	21.30
Helsinki (FI)	5.89	1.86	15.51
Oslo (NO1)	-1.26	1.26	-6.50
Stockholm (SE)	3.45	1.19	12.77
Winter 2 2002 (2209h)	Average traded price (NOK/MWh)	St. dev.	Average of (AP-SP)
Århus (DK1)	4.10	1.81	-100.34
Copenhagen (DK2)	15.18	1.99	-5.25
Helsinki (FI)	4.65	0.74	-16.06
Oslo (NO1)	-1.28	0.58	1.64
Stockholm (SE)	4.00	0.77	-1.72
Year 2002 (8760h)	Average traded price (NOK/MWh)	St. dev.	Average of (AP-SP)
Århus (DK1)	4.11	2.34	-10.25
Copenhagen (DK2)	6.28	3.57	12.70
Helsinki (FI)	3.53	1.12	2.84
Oslo (NO1)	-0.33	0.48	-2.49
Stockholm (SE)	2.22	1.26	5.29
Winter 1 2003 (2879h)	Average traded price (NOK/MWh)	St. dev.	Average of (AP-SP)
Århus (DK1)	-23.93	53.53	-70.50
Copenhagen (DK2)	7.54	5.08	-6.76
Helsinki (FI)	4.25	3.53	-13.36
Oslo (NO1)	0.28	3.42	7.09
Stockholm (SE)	3.96	0.72	-7.60
Summer 2003 (3672h)	Average traded price (NOK/MWh)	St. dev.	Average of (AP-SP)
Århus (DK1)	-0.64	9.58	
Copenhagen (DK2)	6.95	5.81	
Helsinki (FI)	2.68	3.86	
Oslo (NO1)	3.70	2.65	
Stockholm (SE)	3.00	1.91	

Another interesting issue to study is whether the contract prices are over or under the value of the underlying asset (i.e. the daily average of the area price minus the System Price during the delivery period). The calculations are shown in Table 7-5. The payoff from the contracts is equal to the difference between price differential (area price minus System Price) and the average traded price. The contracts with positive payoffs are shown in Table 7-6.

Table 7-6. Positive payoff contracts.

Contract	Payoff (NOK/MWh)
Oslo (NO1) Winter 1 2001	4.40
Oslo (NO1) Summer 2001	1.73
Copenhagen (DK2) Winter 2 2001	9.77
Århus (DK1) Winter 2 2001	9.42
Copenhagen (DK2) Winter 1 2002	10.55
Århus (DK1) Winter 1 2002	10.16
Århus (DK1) Summer 2002	10.12
Copenhagen (DK2) Summer 2002	3.44
Helsinki (FI) Summer 2002	9.62
Stockholm (SE) Summer 2002	9.32
Oslo (NO1) Winter 2 2002	2.92
Copenhagen (DK2) Year 2002	6.42
Stockholm (SE) Year 2002	3.07
Oslo (NO1) Winter 1 2003	6.81

Table 7-6 shows that there is a positive payoff from the Oslo contracts in the first two seasons, Winter 1 and Summer 2001, and for the seasons Winter 2 2002 and Winter 1 2003. The Copenhagen contract shows positive payoff for Winter 2 2001, Winter 1 and Summer 2002 and Year 2002. The Århus contract shows relative high positive payoff for Winter 2 2001, Winter 1 2002, and Summer 2002. For Summer 2002 all contracts except Oslo have positive payoff. The yearly contract for Stockholm has a positive payoff. All other contracts have negative payoff on average (on average the forward price exceeds the spot price differential).

As mentioned earlier this can be interpreted as a negative risk premium for the risk-averse consumers (a forward market in contango). On the other hand a risk-averse generator would require a positive risk premium. The majority of our results are in accordance with the pricing of futures contracts at Nord Pool (Botterud et al., 2002), which also appear to be over-priced relative to the underlying asset. But for these contracts there is relatively little data.

However, some contracts on average are under-priced. According to the risk premium theory, this implies a dominance of risk-averse generators or an excess supply of forward contracts. The Oslo contracts are referred to a hydropower area. The generators are paid the Oslo price (on average lower than the System Price) for their production, while their financial contracts are referred to the System Price. This indicates that a majority of risk-averse generators want to hedge their production in the forward market.

The Århus (except year 2002) and Copenhagen prices have on average been above the System Price since the introduction of these spot areas at Nord Pool. The production in these areas is mainly thermal and the spot prices are relatively high. It is reasonable to assume that the generators are less concerned about hedging their production. A considerable exchange of power between the Nordic region and continental Europe may affect the area prices in Denmark through transmission congestion. Traded combinations of CfDs to hedge against the area price differentials could make it difficult to establish a direct link between the demand of a specific contract and the contract price.

All contracts in the season Summer 2002 except Oslo are under-priced. In this case the market was under-estimating the market value of transmission congestion.

The trading price should reflect the prediction of the market regarding the price differential as defined in Equation (7.5) during the delivery period. Table 7-6 shows that the prices vary from the underlying asset. This is not surprising, because unforeseen shocks during the settlement period (e.g. unexpected constraints due to plant and line outages as well as relative demand in each region) are bound to occur.

The underlying asset is also highly volatile, even more than the Area and System Prices themselves. The magnitude of the standard deviation is several times the magnitude of the price differential. Since the underlying asset is expected to be uncertain, the traded forward contract may have incorporated this uncertainty in the price. Parameters used to calculate the security requirements were changed in January 2001, because they generally were too high. This affected the contracts referred to Helsinki, Stockholm, Oslo and Århus.

Forecasting transmission congestion is a difficult task. The information available to the market players is forecasts of the inflow, area prices and System Price. The reliability of these forecasts for a longer period than the closest weeks is relatively low. Since transmission congestion is highly dependent on the inflow situation (dry versus wet years), the hydrological balance in an area can be used as to measure the probability of congestion. Another analysis tool is the EMPS-model (Haugestad and Rismark, 1998), which is used for optimization and simulation of hydro-thermal systems with a considerable share of hydropower. The model takes into account transmission constraints and hydrological differences among major areas or regional subsystems. The objective is an optimal use of hydro resources in relation to future inflows, thermal generation, electricity demand and spot transactions within or between the areas. The weakness of the model is that its grid representation may be inaccurate. A precise description of the Nordic power system requires a model with frequently updated data.

7.8 Policy issues

Energy policy affects derivatives mainly through its impacts on the underlying commodity and transmission markets (Energy Information Administration, 2002). Electricity markets with large numbers of informed buyers and sellers, each with objectives of moving the commodity to where it is needed, support competitive prices. Derivatives for managing local price risks are then based on the overall market price with relatively small, predictable adjustments for moving the electricity to local users. Energy policy affects competitors' access to transmission, the volatility of transmission charges, and therefore derivative markets.

Efforts to reduce price volatility have focused on increasing both reserve production capacity and transmission capability. There has also been an effort to make real-time prices more visible to users to help limit the size and duration of price spikes.

Competitive electricity markets require competitive, reliable transmission markets. A network with sufficient capacity to supply high price areas stimulates competition. However, creating competitive transmission markets has proven difficult. Competitive transmission charges are the marginal cost of moving power. For example in the US (except in a few locations) transmission charges are currently set arbitrarily with no regard to the marginal cost. Many states actively discourage transmission of their cheap power to higher cost areas in neighboring states. The result is a fragmented market where trade does not create consistent electricity prices.

Some barriers to the development of the electricity derivatives market are:

- As a commodity, electricity has many unique aspects, including instantaneous delivery, non-storability, an interactive delivery system, and extreme price volatility.
- The complexity of electricity spot markets is not conducive to common futures transactions.
- There are also substantial problems with price transparency, modeling of derivative instruments, effective arbitrage, credit risk, and default risk.

Because there are problems with the price models, innovative derivatives based on something other than the underlying energy spot price (e.g. weather derivatives, marketable emissions permits, and specialty insurance contracts) will be important in the future. Forward contracts using increasingly standardized terms are likely to be supplied in addition to futures contracts.

The Nordic region has a mature and liquid forward and futures market. There is confidence in Nord Pool that is owned by the Norwegian and Swedish TSOs. There has been 60-70% annual growth in the financial market in recent years (Nord Pool, 2002c). The regulatory framework has been committed to facilitate trade and establish a liquid spot market. Nord Pool offers easy access to information and provides price transparency. Large industrial consumers and generation companies may therefore hedge their consumption/generation and decrease their risks. Nord Pool facilitates trade of CfDs to hedge against the price differences resulting from transmission congestion. The market prices of these contracts indicate the market's expectation of transmission congestion. For long-term contracts it may provide information about the value of building a transmission line between two regions.

Continental Europe's electricity exchanges are less liquid and traders must rely more on OTC markets for hedging. To purchase physical transmission capacity, players may participate in cross-border auctions. In recent years, they have established as a method to allocate cross-border transmission capacity in cases where demand exceeds supply. The price of transmission capacity can be highly volatile (E.ON Netz, 2003).

The PJM and New York power markets have financial transmission rights. These forward contracts are purely financial and entitle the holders to a payment equal to the future difference in locational prices times the contractual power. The independent system operator issues these contracts, which are supposed to redistribute the congestion rents the system operator collects during congestion. In the Nordic market the CfDs have no connection to the congestion rent the system operator collects.

7.9 Conclusions

This chapter has demonstrated how Nord Pool prices CfDs for the first eight trading periods. Based on a comparison between the trading prices of the contracts and the average of the seasonal area price minus the System Price during the settlement period, they appear to be over-priced on average ex post. The explanation may be the presence of a majority of risk-averse consumers who are willing to pay a risk premium for receiving the future price differential. If the price differential in a given area is positive, the consumers are penalized if they have purchased a forward contract related to the System Price. They are risk-averse if they pay for the contract at a price greater than the expected price differential. If the price differential is negative, generators are penalized, and they are risk-averse if they pay for a contract that is more expensive than the expected price differential (in absolute value).

This work also considered contracts that were under-priced ex post. For the Oslo contracts this may be explained by the presence of a majority of risk-averse hydropower generators wanting to hedge their production in the forward market. The prices of the contracts depend on the inflow in the actual year which is an important factor in creating transmission congestion. Since every contract is referred to a season or a year, this makes the present amount of data limited. As far I am aware, this is the first survey of how CfDs have been priced.

8 A merchant mechanism for electricity transmission expansion[95]

A merchant mechanism to expand electricity transmission is proposed which is based on long-term financial transmission rights (FTRs). Due to network loop flows, a change in network capacity might imply negative externalities on existing transmission property rights. The system operator thus needs a protocol for awarding incremental FTRs that maximize investors' preferences, and preserves certain currently unallocated FTRs (or proxy awards) so as to maintain revenue adequacy. This chapter defines a proxy award as the best use of the current network along the same direction as the incremental awards. It then develops a bi-level programming model for allocation of long-term FTRs according to this rule and applies it to different network topologies. One finding is that simultaneous feasibility for a transmission expansion project crucially depends on the investor-preference and the proxy-preference parameters. Likewise, for a given amount of pre-existing FTRs and the larger the current capacity the greater the need to reserve some FTRs for possible negative externalities generated by the expansion changes.

8.1 Introduction

The analysis of incentives for electricity transmission expansion is not easy. Beyond economies of scale and cost sub-additivity externalities in electricity transmission are mainly due to "loop flows" that come up from complex network interactions.[96] The effects of loop flows imply that transmission opportunity costs are a function of the marginal costs of energy at each location. Power costs and transmission costs depend on each other since they are simultaneously settled in electricity dispatch. Loop flows imply that certain transmission investments might have negative externalities on the capacity of other (perhaps distant) transmission links (see Bushnell and Stoft, 1997). Moreover, the addition of new transmission capacity can sometimes paradoxically decrease the total capacity of the network (Hogan, 2002a).

The welfare effects of an increment in transmission capacity are analyzed by Léautier (2001). The welfare outcome of an expansion in the transmission grid depends on the weight in the welfare function of the generators' profits relative to the consumers' utility weight. Incumbent generators are not in general the best agents to carry out transmission expansion projects. Even though an increase in transmission capacity might allow them to engross their revenues due to increased access to new markets and higher transmission charges, such gains are usually overcome by the loss of their local market power.

The literature on incentives for long-term expansion of the transmission network is scarce. The economic analysis of electricity markets has been reduced to short-run issues, and has typically assumed that transmission capacity is fixed (see Joskow and Tirole, 2003). However, transmission capacity is random in nature, and it jointly depends on generation investment.

The way to solve transmission congestion in the short-run is well known. In a power flow model, the price of transmission congestion is determined by the

[95] I am grateful for comments from William Hogan and Ross Baldick.
[96] See Joskow and Tirole (2000), and Léautier (2001).

difference in locational prices (see Hogan, 1992, 2002b). Yet, there is no consensus with respect to the method to attract investment to finance the long-term expansion of the transmission network, so as to reconcile the dual opposite incentives to congest the network in the short-run, and to expand it in the long-run. Incentive structures proposed to promote transmission investment range from a "merchant" mechanism, based on long-term financial transmission rights (LTFTRs) auctions (as in Hogan, 2002a), to regulatory mechanisms that charge the transmission firm the social cost of transmission congestion (see Léautier 2000, Vogelsang, 2001, and Joskow and Tirole, 2002).

In practice, regulation has been used in the United Kingdom and Norway to promote transmission expansion, while a combination of planning and auctions of long-term transmission rights has been tried in the Northeast of the U.S. A mixture of regulatory mechanisms and merchant incentives is alternatively used in the Australian market.

This chapter develops a merchant model to attract investment to *small-scale*[97] electricity transmission projects based on LTFTRs auctions. Locational prices give market players incentives to initiate transmission investments. FTRs provide transmission property rights, since they hedge the market player against future price differences. The model further develops basic conditions under which FTRs and locational pricing provide incentives for long-term investment in the transmission network.

In meshed networks, a change in network capacity might imply negative externalities on transmission property rights. Then, in the process of allocation of incremental FTRs, the system operator has to reserve certain unallocated FTRs so that the revenue adequacy of the transmission system is preserved. In order to deal with this issue, we develop a bi-level programming model for allocation of long-term FTRs and apply it to different network topologies.

The structure of the chapter is as follows. Section 8.2 carries out an analytical review on the relevant literature on electricity transmission expansion. Section 8.3 develops the model. This first introduces FTRs and the feasibility rule, and then addresses the rationale for FTR allocation and efficient investments. It then develops general optimality conditions as well. Section 8.4 carries out applications of the model to a radial line, and to a three-node network. Finally, section 8.5 gives the concluding comments.

8.2 Literature review

Among the hypotheses on structures for transmission investment, we have the market-power hypothesis, the incentive-regulation hypothesis, and the long-run financial-transmission-right hypothesis. The first approach seeks to derive optimal transmission expansion from the power-market structure of power generators, and takes into account the conjectures of each generator regarding other generators' marginal costs due to the expansion (Sheffrin and Wolak, 2001, Wolak, 2000, and

[97] Small-scale can be interpreted in various ways. For example investments in proper maintenance and upgrades increase thermal line limits without changing the power transfer distribution factors (PTDFs). Here the discussion is including investments with no or small scale to returns that may change the PTDFs.

California ISO and London Economics International, 2003). The generators' bidding behavior is estimated before and after a transmission upgrade, and a real-option analysis is used to derive the net present value of transmission and generation projects together with the computation of their joint probability.

The model shows that there are few benefits of transmission expansion until added capacity surpasses a certain threshold that, in turn, is determined by the possibility of induced congestion by the strategic behavior of generators with market power. The generation market structure then determines when transmission expansion yield benefits. Additionally, many small upgrades of the transmission grid result to be preferable to large greenfield projects when cost uncertainty is added to the model.

The contribution of this method is that it models the existing interdependence of the transmission investment and generation investment within a transportation model with no network loop flows. However, as pointed out by Hogan (2002b), the use of a transportation model in the electricity sector is inadequate since it does not deal with discontinuities in transmission capacity implied by the multidimensional character of a meshed network.

The second method for transmission expansion is a regulatory alternative that relies on a "Transco" that simultaneously runs system operation and owns the transmission network. The Transco is regulated through benchmark regulation or price regulation so as to provide it with incentives to invest in the development of the grid, while avoiding congestion. Léautier (2000), Grande and Wangesteen (2000), and Harvard Electricity Policy Group (2002) discuss mechanisms that compare the Transco performance with a measure of welfare loss due to its activities. Joskow and Tirole (2002) propose a surplus-based mechanism to reward the Transco according to the redispatch costs avoided by the expansion, so that the Transco faces the complete social cost of transmission congestion.

Another regulatory alternative is a two-part tariff cap proposed by Vogelsang (2001) that solves the opposite incentives to congest the existing transmission grid in the short-run, and to expand it in the long-run. Incentives for investment in expansion of the network are achieved through the rebalancing of the fixed part and the variable part of the tariff. This method tries to deepen into the analysis of the cost and production functions for transmission services, which are not very well understood in the economics literature. Nonetheless, to achieve this goal Vogelsang needs to define an output (or throughput) for the Transco. As argued in the FTR literature (Bushnell and Stoft, 1997; Hogan, 2002a; Hogan, 2002b), this task is very difficult since the physical flow through a meshed transmission network cannot be traced.

The third approach is a "merchant" one based on LTFTR auctions by an independent system operator (ISO). This method deals with loop-flow externalities in that, to proceed with line expansions, the investor pays for the negative externalities it generates. To restore feasibility, the investor has to buy back sufficient transmission rights from those who hold them initially. This is the core of an LTFTR auction (see Hogan, 2002a).

Joskow and Tirole (2003) criticize the LTFTR approach. They argue that the efficiency results of the *short-run* version of the FTR model rely on perfect-competition assumptions, which are not real for transmission networks. Moreover, defining an operational FTR auction is technically difficult[98] and, according to these authors, the FTR analysis is static (a contradiction with the dynamics of transmission investment). Joskow and Tirole analyze the implications of eliminating the perfect competition assumptions of the FTR model.

First, market power and vertical integration might impede the success of FTR auctions. Prices will not reflect the marginal cost of production in regions with transmission constraints. Generators in constrained regions will then withdraw capacity in order to increase their prices, and will overestimate the cost-saving gains from investments in transmission.[99]

Second, lumpiness in transmission investment makes the total value paid to investors through FTRs less than the social surplus created. The large and lumpy nature of major transmission upgrades requires long-term contracts before making the investment, or temporal property rights for the incremental investment.

Third, contingencies in electricity transmission impede the merchant approach to really solve the loop-flow problem. Moreover, existing transmission capacity and incremental capacity are stochastic. Even in a radial line, realized capacity could be less than expected capacity and the revenue-adequacy condition would not be met. Even more, the initial feasible FTR set can depend on random exogenous variables.

Fourth, an expansion in transmission capacity might negatively affect social welfare (as shown by Bushnell and Stoft, 1997).

Finally, there is a "moral hazard in teams" problem. This arises due to the separation of transmission ownership and system operation in the FTR model. For instance, an outage can be claimed to be the consequence of poor maintenance (by the transmission owner) or of negligent dispatch (by the system operator).[100] Additionally, there is no perfect coordination of interdependent investments in generation and transmission, and stochastic changes in supply and demand conditions imply uncertain nodal prices. Likewise, there is no equal access to investment

[98] No restructured electricity sector in the world has adopted a pure merchant approach towards transmission expansion. Australia has implemented a mixture of regulated and merchant approaches (see Littlechild, 2003). Pope and Harvey (2002) propose LTFTR auctions for the New York ISO to provide a hedge against congestion costs. Gribik et al. (2002) propose an auction method based on the physical characteristics (capacity and admittance) of a transmission network.

[99] Generators can exert local power when the transmission network is congested. (See Bushnell, 1999, Bushnell and Stoft, 1997, Joskow and Tirole, 2000, Oren,1997, Joskow and Schmalensee, 1983, Chao and Peck, 1997, Gilbert, Neuhoff, and Newbury, 2002, Cardell, Hitt, and Hogan, 1997, Borenstein, Bushnell, and Stoft, 1998, Wolfram, 1998, and Bushnell and Wolak, 1999). There may be cases where transmission expansion FTRs mitigate market power such as when a generator builds a line to a high price region and creates new capacity.

[100] An example is the power outage of August 15, 2003, in the Northeast of the US, which affected six control areas (Ontario, Quebec, Midwest, PJM, New England, and New York) and more than 20 million consumers. A 9-second transmission grid technical and operational problem caused a cascade effect, which shut down 61000 MW generation capacity. After the event there were several "finger pointings" among system operators of different areas, and transmission providers.

opportunities since only the incumbent can efficiently carry out deepening transmission investments.

Hogan (2003) responds to the above criticisms by arguing that LTFTRs only grant efficient outcomes under lack of market power, and non-lumpy marginal expansions of the transmission network. Hogan argues that regulation has an important role in fostering large and lumpy projects, and in mitigating market power abuses.

As argued by Pérez-Arriaga et al. (1995), revenues from nodal prices only recover 25% of total costs. LTFTRs should then be complemented with a fixed-price structure or, as in Rubio-Odériz and Pérez-Arriaga (2000) a *complementary charge* that allows the recovery of fixed costs.[101] This is recognized by Hogan (1999b) who argues that complete reliance on market incentives for transmission investment is undesirable. Rather, Hogan (2003) argues that merchant and regulated transmission investments might be combined so that regulated transmission investment is limited to projects where investment is large relative to market size, and lumpy so that it only makes sense as a single project as opposed as to many incremental small projects.

Hogan also responds to contingency concerns.[102] On the one hand, only those contingencies outside the control of the system operator could lead to revenue inadequacy of FTRs, but such cases are rare and do not represent the most important contingency conditions. On the other hand, most of remaining contingencies are foreseen in a security-constrained dispatch of a meshed network with loops and parallel paths. If one of "*n*" transmission facilities is lost, the remaining power flows would still be feasible in an "*n*-1" contingency constrained dispatch.

Hogan (2003) also assumes that agency problems and information asymmetries are part of an institutional structure of the electricity industry where the ISO is separated from transmission ownership and where market players are decentralized. However, he claims that the main issue on transmission investment is the decision of the boundary between merchant and regulated transmission expansion projects. He states that asymmetric information should not necessarily affect such a boundary.

Hogan (2002a) finally analyzes the implications of loop flows on transmission investment raised by Bushnell and Stoft (1997). He analytically provides some general axioms to properly define LTFTRs so as to deal with negative externalities implied by loop flows. The next section presents a model that develops the general analytical framework proposed by Hogan (2002a).

8.3 The model

Assume an institutional structure where there are various established agents (generators, Gridcos, marketers, etc.) interested in the transmission grid expansion. Agents do not have market power in their respective market or, at least, there are in place effective market-power mitigation measures.[103] Also assume that transmission

[101] In the US, transmission fixed costs are recovered through a regulated fixed charge, even in those systems that are based on locational pricing and FTRs. This charge is usually regulated through cost of service.
[102] See Hogan Hogan (2002b) and Hogan (2003).
[103] In fact, market power mitigation may be a major motive for transmission investment. A generator located outside a load pocket might want to access the high price region inside the

projects are incrementally small (relative to the total network) and non-lumpy so that the project does not imply a relatively large change in locational price differences. However, although projects are small, they might change or not the power transfer distribution factors (PTDFs) of the network.[104]

Under an initial condition of non-fully allocation of FTRs in the grid, the auctioning of incremental LTFTRs should satisfy the following basic criteria in order to deal with possible negative externalities associated with the expansion

1. An LTFTR increment must keep being simultaneously feasible (*feasibility rule*).
2. An LTFTR increment remains simultaneously feasible given that certain currently unallocated rights (or *proxy awards*) are preserved.
3. Investors should maximize their objective function (*maximum value*).
4. The LTFTR awarding process should apply both for decreases and increases in the grid capacity (*symmetry*).

Hogan explains that defining proxy awards is a difficult task. We next address this issue in a formal way in the context of an auction model designed to attract investment for transmission expansion.

8.3.1 The power flow model and proxy awards

Consider the following economic dispatch model:[105]

$$\begin{aligned} &\underset{Y,u\in U}{Max}\, B(d-g) \\ &s.t. \end{aligned} \tag{8.1}$$

$$Y = d - g, \tag{8.2}$$

$$L(Y,u) + \tau^T Y = 0 \tag{8.3}$$

$$K(Y,u) \leq 0 \tag{8.4}$$

where d and g are load and generation at the different locations. The variable Y represents the real power bus net loads, including the swing bus S ($Y^T = (Y_s, \bar{Y}^T)$). *B(d-g)* is the net benefit function,[106] and τ is a unity column vector, $\tau^T = (1,1,...,1)$. All

pocket. Building a new line would mitigate market power if it creates new economic capacity (see Joskow and Tirole, 2000).

[104] Examples of projects that do not change PTDFs include proper maintenance and upgrades (e.g. low sag wires), and the capacity expansion of a radial line or of a single line in a three-node network. Such investments could be rewarded with flowgate rights in the incremental capacity without affecting the existing FTR holders (it is assumed however that only FTRs are issued). In a large-scale meshed network the change in PTDFs may not be as substantial as in a three-node network. However, the auction problem is non-convex and non-linear, and a global optimum might not be ensured. Only a local optimum might be found through sequential quadratic programming.

[105] Hogan (2002b) shows that the economic dispatch model can be extended to a market equilibrium model where the ISO produces transmission services, power dispatch, and spot-market coordination, while consumers have a concave utility function that depends on net loads, and on the level of consumption of other goods.

[106] Function *B* is typically a measure of welfare, such as the difference between consumer surplus and generation costs (see Hogan, 2002b)

other parameters are represented in the control variable u. The objective Equation (8.1) includes the maximization of benefit to loads and the minimization of generation costs. Equation (8.2) denotes the net load as the difference between load and generation. Equation (8.3) is a loss balance constraint where $L(Y,u)$ denotes the losses in the network. In Equation (8.4) $K(Y,u)$, is a vector of power flows in the lines, which are subject to transmission capacity limits. The corresponding multipliers or shadow prices for the constraints are $(P, \lambda_{ref}, \lambda_{tran})$ for net loads, reference bus energy (or loss balance) and transmission constraints, respectively.[107]

The locational prices P are the marginal generation cost or the marginal benefit of demand, which in turn equals the reference price of energy plus the marginal cost of losses and congestion. With the optimal solution (d^*, g^*, Y^*, u^*) and the associated shadow prices, we have the vector of locational prices as:

$$P^T = \nabla C(g^*) = \nabla B(d^*) = \lambda_{ref}\tau^T + \lambda_{ref}\nabla L_Y(Y^*, u^*) + \lambda_{tran}^T \nabla K_Y(Y^*, u^*) \tag{8.5}$$

If losses[108] are ignored, only the energy price at the reference bus and the marginal cost of congestion contribute to set the locational price.

FTR obligations[109] hedge market players against differences in locational prices caused by transmission congestion.[110] FTRs are provided by an ISO, and are assumed to redistribute the congestion rents. The payoff from these rights is given by:

$$FTR = (P_j - P_i)Q_{ij} \tag{8.6}$$

where P_j is the price at location j, P_i is the price at location i, and Q_{ij} is the directed quantity from point i to point j specified in the FTR. The FTR payoffs can take negative, positive or zero values.

A set of FTRs is said to be simultaneously feasible if the associated set of net loads is simultaneously feasible, that is if the net loads satisfy the loss balance and transmission capacity constraints as well as the power flow equations given by:

107 When security constraints are taken into account (n-1 criterion) this is a large-scale problem, and it prices anticipated contingencies through the security-constrained economic dispatch. In operations the n-1 criterion can be relaxed on radial paths, however, doing the same in the FTR auction of large-scale meshed networks may result in revenue inadequacy. The n-1 criterion is not used in this work.

108 In the PJM (Pennsylvania, New Jersey and Maryland) market design, the locational prices are defined without respect to losses (DC load flow), while in New York the locational prices are calculated based on an AC network with marginal losses.

109 FTRs could be options with a payoff equal to max($(P_j - P_i)\, Q_{ij}$,0). Then a negative price difference would result in zero payoff.

110 See Hogan (1992).

$$Y = \sum_k t_k^f$$
$$L(Y,u) + \tau' Y = 0, \qquad (8.7)$$
$$K(Y,u) \le 0$$

where $\sum_k t_k^f$ is the set of point-to-point obligations.[111]

If the set of FTRs is simultaneously feasible and the system constraints are convex,[112] then the FTRs satisfy the *revenue adequacy* condition in the sense that equilibrium payments collected by the ISO through economic dispatch will be greater than or equal to payments required under the FTR forward obligations.[113]

Assume now that there are investments in new transmission capacity. The associated set of new FTRs for transmission expansion has to satisfy the simultaneous feasibility rule too. That is, the new and old FTRs have to be simultaneously feasible after the system expansion. Assume that T is the current partial allocation of long-term FTRs, then by assumption it is feasible ($K(T,u) \le 0$). Let a be the scalar amount of incremental FTR awards**,** and $\hat{t}$ the scalar amount of proxy awards. Furthermore let δ be directional vector[114] such that $a\delta$ is the MW amount of incremental FTR awards**,** and $\hat{t}\delta$ is the MW amount of proxy awards between different locations. Any incremental FTR award $a\delta$ should comply with feasibility rule in the expanded grid. Hence we must have $K^{+}(T+a\delta,u) \le 0$.

When certain currently unallocated rights (proxy awards) $\hat{t}\delta$ in the existing grid must be preserved, combined with existing rights they sum up to $T+\hat{t}\delta$.[115] Then the expanded grid K^{+} should also satisfy simultaneous feasibility so that $K^{+}(T+a\delta,u) \le 0$ and $K^{+}(T+\hat{t}\delta+a\delta,u) \le 0$ for incremental awards $a\delta$.

A question then arises regarding the way to best define proxy awards. One possibility is to define them as the "best use" of the current network along the same direction as the incremental awards.[116] This includes both positive and negative

[111] The set of point-to-point obligations can be decomposed into a set of balanced and unbalanced (injection of energy) obligations (see Hogan 2002b).

[112] This has been demonstrated for lossless networks by Hogan (1992), extended to quadratic losses by Bushnell and Stoft (1996), and further generalized to smooth nonlinear constraints by Hogan (2000). As shown by Philpott and Pritchard (2004) negative locational prices may cause revenue inadequacy. Moreover, in the general case of an AC or DC formulation the transmission constraints must be convex to ensure revenue adequacy (O'Neill et al., 2002; Philpott and Pritchard, 2004).

[113] Revenue adequacy is the financial counterpart of the physical concept of availability of transmission capacity (see Hogan, 2002a).

[114] Each element in the directional vector represents an FTR between two locations and the directional vector may have many elements representing combinations of FTRs.

[115] Proxy awards are then currently unallocated FTRs in the pre-existing network that basically facilitate the allocation of incremental FTRs and help to preserve revenue adequacy by reserving capacity for hedges in the expanded network

[116] Another possibility would be to define every possible use of the current grid as a proxy award. However, this would imply that any investment beyond a radial line would be

incremental FTR awards. The best use in a three-node network may be thought of as a single incremental FTR in one direction or a combination of incremental FTRs defined by the directional vector δ, which the investor has preference for. Hogan (2002a) proposes two ways of defining "best use:"

$$\begin{aligned}
&\text{Preset proxy preferences } (p)\\
&\hat{y} = T + \hat{t}\delta,\\
&\hat{t} \in \arg\max_{t} \left\{ \hat{t}p\delta \mid K(T + t\delta) \le 0 \right\}\\
&\text{or,} \qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad (8.8)\\
&\text{Investor preferences } (\beta(\mathrm{a}\delta))\\
&\hat{y} = T + \hat{t}\delta,\\
&\hat{t} \in \arg \min_{\substack{t\\ K(T+t\delta)\le 0}} \left\{ \max_{a\ge 0} \left\{ \beta(a\delta) \mid K^{+}(T + t\delta + a\delta) \le 0 \right\} \right\}
\end{aligned}$$

In the preset proxy formulation the objective is to maximize the value (defined by prices p) of the proxy awards given the pre-existing FTRs, and the power flow constraints in the pre-expansion network. In the investor preference formulation the objective is to maximize the investor's value (defined by the bid functions for different directions, $\beta(a\delta)$) of incremental FTR awards given the proxy and pre-existing FTRs and the power flow constraints in the expanded network, while simultaneously calculating the minimum proxy scalar amount that satisfies the power flow constraints in the pre-expansion network.

We will use the first definition as a proxy protocol. We can now analyze the way to use this protocol to carry out an allocation of LTFTRs that stimulates investment in transmission.

8.3.2 The auction model

Assume the preset proxy rule is used to derive prices that maximize the investor preference $\beta(a\delta)$ for an award of a MWs of FTRs in direction δ. We then have the following auction maximization problem:

$$\begin{aligned}
&\underset{a,\hat{t},\delta}{Max}\;\; \beta(a\delta)\\
&s.t.\\
&K^{+}(T + a\delta) \le 0, \qquad\qquad\qquad\qquad (8.9)\\
&K^{+}(T + \hat{t}\delta + a\delta) \le 0,\\
&\hat{t} \in \arg\max_{t} \left\{ tp\delta \mid K(T + t\delta) \le 0 \right\},\\
&\|\delta\| = 1,\\
&a \ge 0.
\end{aligned}$$

precluded, and that incremental award of FTRs might require adding capacity to every link on every path of a meshed network.

In this model, the investor's preference is maximized subject to the simultaneous feasibility conditions, and the best use protocol. We add a constraint on the norm of the directional vector to preclude the trivial case $\delta = 0$. We want to explore if such an auction model approach can produce acceptable proxy and incremental awards. We next analyze this issue within a framework that ignores losses, and utilizes a DC-load approximation.

The auction model is a nonlinear optimization problem of "bi-level" nature.[117] There are two optimization stages. Maximization is non-myopic since the result of the lower problem (first stage) depends on the direction chosen in the upper problem (second stage).[118] Bi-level problems are solved by first transforming the lower problem (i.e. the allocation of proxy awards) into to a set of Kuhn-Tucker equations that are subsequently substituted in the upper problem (i.e. the maximization of the investors' preference). The model can then be understood as a Stackelberg problem although it is not intending to optimize the same type of objective function at each stage.[119]

The Lagrangian (L) for the lower problem is:

$$L(\hat{t},\delta,\lambda) = \hat{t}p\delta - \lambda^T (K(T + \hat{t}\delta))$$

where λ^T is the Lagrange multiplier vector associated with transmission capacity on the respective transmission lines before the expansion. It is the Lagrange multiplier of the simultaneous feasibility restriction for proxy awards. The Kuhn-Tucker conditions are:

$$\frac{\partial L(\hat{t},\delta,\lambda)}{\partial \hat{t}} = 0, \quad \frac{\partial L(\hat{t},\delta,\lambda)}{\partial \lambda} \geq 0$$

$$\lambda^T \frac{\partial L(\hat{t},\delta,\lambda)}{\partial \lambda} = 0, \quad \lambda \geq 0$$

The transformed problem is then written as:

$$\begin{aligned}
&\underset{a,\hat{t},\delta,\lambda}{Max} \ \beta(a\delta) \\
&s.t. \\
&K^+(T + a\delta) \leq 0, && (\omega) \\
&K^+(T + \hat{t}\delta + a\delta) \leq 0, && (\gamma) \\
&\frac{\partial L(\hat{t},\delta,\lambda)}{\partial \hat{t}} = 0, && (\theta)
\end{aligned}$$

[117] See Shimizu et al. (1997).
[118] The model could also be interpreted as having multiple periods. Although a discount factor is not explicitly included in the model, it is included in the investor's preference parameter *b*.
[119] Other examples in the economics literature where an upper level maximization takes the optimality conditions of another problem as constraints are given in Mirrlees (1971), Brito and Oakland (1977), and Rosellón (2000).

$$\lambda^T \frac{\partial L(\hat{t},\delta,\lambda)}{\partial \lambda} = 0, \qquad (\zeta) \tag{8.10}$$
$$\frac{\partial L(\hat{t},\delta,\lambda)}{\partial \lambda} \geq 0, \qquad (\varepsilon)$$
$$\|\delta\| = 1, \qquad (\varphi)$$
$$a \geq 0, \qquad (\kappa)$$
$$\lambda \geq 0 \qquad (\pi)$$

where $\omega, \gamma, \theta, \zeta, \varepsilon, \varphi, \kappa$ and π are Lagrange multipliers associated with each constraint. More specifically, ω is the shadow price of the simultaneous feasibility restriction for existing and incremental FTRs; γ is the shadow price of the simultaneous feasibility restriction for existing FTRs, proxy awards and incremental FTRs; $\theta, \varsigma, \varepsilon$ are the shadow prices of the restriction on optimal proxy FTRs; φ, κ are the shadow prices of the non-negativity constraints for a and λ, respectively; and π is the shadow price of the unit restriction on δ.

The Lagrangian of the auction problem is:

$$\begin{aligned} L(a,\hat{t},\delta,\lambda,\Omega) &= \beta(a\delta) - \omega^T (K^+(T + a\delta)) \\ &-\gamma^T (K^+(T + \hat{t}\delta + a\delta)) - \theta^T \frac{\partial L(\hat{t},\delta,\lambda)}{\partial \hat{t}} \\ &-\zeta^T (\lambda^T \frac{\partial L(\hat{t},\delta,\lambda)}{\partial \lambda}) + \varepsilon^T \frac{\partial L(\hat{t},\delta,\lambda)}{\partial \lambda} \\ &+\varphi^T (1 - \|\delta\|) + \kappa^T a + \pi^T \lambda \end{aligned} \tag{8.11}$$

where $\Omega = (\omega, \gamma, \theta, \zeta, \varepsilon, \varphi, \kappa, \pi)$ denotes the vector of Lagrange multipliers. Kuhn-Tucker conditions for the upper problem are:

$$\begin{aligned} \frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial a} &= \frac{\partial \beta(a\delta)}{\partial a} - \left[\frac{\partial K^+(T + a\delta)}{\partial a}\right]^T \omega \\ &- \left[\frac{\partial K^+(T + \hat{t}\delta + a\delta)}{\partial a}\right]^T \gamma + \kappa = 0 \end{aligned} \tag{8.12}$$

$$\begin{aligned} \frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \delta} &= \frac{\partial \beta(a\delta)}{\partial \delta} - \left[\frac{\partial K^+(T + a\delta)}{\partial \delta}\right]^T \omega \\ &- \left[\frac{\partial K^+(T + \hat{t}\delta + a\delta)}{\partial \delta}\right]^T \gamma - \left[\frac{\partial^2 L(\hat{t},\delta,\lambda)}{\partial \delta \partial \hat{t}}\right]^T \theta \\ &- \left[\frac{\partial^2 L(\hat{t},\delta,\lambda)}{\partial \delta \partial \lambda}\right]^T \lambda\zeta + \left[\frac{\partial^2 L(\hat{t},\delta,\lambda)}{\partial \delta \partial \lambda}\right]^T \varepsilon - \left[\frac{\partial \|\delta\|}{\partial \delta}\right]^T \varphi = 0 \end{aligned} \tag{8.13}$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \hat{t}} = -\left[\frac{\partial K^{+}(T+\hat{t}\delta+a\delta)}{\partial \hat{t}}\right]^{T}\gamma \tag{8.14}$$

$$-\left[\frac{\partial^{2} L(\hat{t},\delta,\lambda)}{\partial \hat{t}\partial\lambda}\right]^{T}\lambda\zeta + \left[\frac{\partial L^{2}(\hat{t},\delta,\lambda)}{\partial \hat{t}\partial\lambda}\right]^{T}\varepsilon = 0$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \lambda} = -\left[\frac{\partial^{2} L(\hat{t},\delta,\lambda)}{\partial\lambda\partial \hat{t}}\right]^{T}\theta - \left[\frac{\partial L(\hat{t},\delta,\lambda)}{\partial\lambda}\right]^{T}\zeta + \pi = 0, \tag{8.15}$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \omega} = -K^{+}(T+a\delta) \geq 0, \tag{8.16}$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\delta\gamma} = -K^{+}(T+\hat{t}\delta+a\delta) \geq 0 \tag{8.17}$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \theta} = -\frac{\partial L(\hat{t},\delta,\lambda)}{\partial \hat{t}} = 0, \tag{8.18}$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \zeta} = -\lambda^{T}\frac{\partial L(\hat{t},\delta,\lambda)}{\partial\lambda} = 0, \tag{8.19}$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \varepsilon} = \frac{\partial L(\hat{t},\delta,\lambda)}{\partial\lambda} \geq 0, \tag{8.20}$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \varphi} = 1 - \|\delta\| = 0, \tag{8.21}$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \kappa} = a \geq 0, \tag{8.22}$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \pi} = \lambda \geq 0, \tag{8.23}$$

$$\omega^{T}\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \omega} = 0,\ \omega \geq 0, \tag{8.24}$$

$$\gamma^{T}\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \gamma} = 0,\ \gamma \geq 0, \tag{8.25}$$

$$\varepsilon^{T}\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \varepsilon} = 0,\ \varepsilon \geq 0, \tag{8.26}$$

$$\kappa^{T}a = 0,\ \kappa \geq 0, \tag{8.27}$$

$$\pi^{T}\lambda = 0, \pi \geq 0 \tag{8.28}$$

The constraint $\frac{\partial L(\hat{t},\delta,\lambda)}{\partial\lambda} = 0$ is redundant when the preset proxy preference (p) is non-zero, since it is a sub-gradient of the constraint $\lambda^{T}\frac{\partial L(\hat{t},\delta,\lambda)}{\partial\lambda} = 0$, and ε is therefore zero when p is non-zero. We show in a later example that θ and φ are zero because the associated constraints are redundant. The binding constraint in the lower level problem is $\lambda^T \dfrac{\partial L(\hat{t},\delta,\lambda)}{\partial \lambda} = 0$, since some transmission constraints are fully utilized by proxy awards.

This is a nonlinear and non-convex problem, and its solution depends on the initial value of the bid parameter (*b*), the current partial allocation (*T*), and the topology of the network prior to and after the expansion.[120] A general solution method utilizing Kuhn-Tucker conditions would be through checking which of the constraints are binding.[121] One way to identify the active inequality constraints is the active set method.[122] This chapter solves the problem in detail for different network topologies, including a radial line and a three-node network.

8.4 Numerical results

8.4.1 Radial line

Let us first analyze a radial transmission line that is expanded as in Figure 8-1.

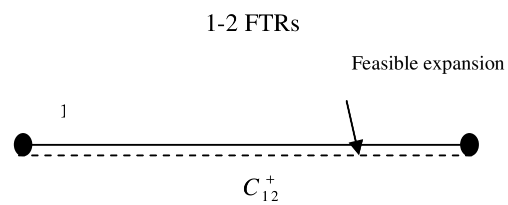

Figure 8-1. An expanded line and its feasible expansion.

The corresponding optimization problem is:

$$
\begin{aligned}
&\underset{a,\hat{t},\delta}{Max}\ \ b_{12} a \delta_{12} \\
&s.t. \\
&T_{12} + a\delta_{12} \le C^+_{12} \\
&T_{12} + \hat{t}\delta_{12} + a\delta_{12} \le C^+_{12} \\
&\hat{t}(\delta_{12}) \in \arg\max_t \{\ tp_{12}\delta_{12} \mid T_{12} + t\delta_{12} \le C_{12} \} \\
&\|\delta_{12}\| = 1, \\
&a \ge 0
\end{aligned}
\qquad (8.29)
$$

[120] According to Shimizu et al. (1997), the necessary optimality conditions for this problem are satisfied. The objective function and the constraints are differentiable functions in the region bounded by the constraints. A local optimal solution and Kuhn-Tucker vectors then exist.

[121] There are other methods available such as transformation methods (penalty and multiplier), and non-transformation methods (feasible and infeasible). See Shimizu et al. (1997).

[122] This method considers a tentative list of constraints that are assumed to be binding. This is a working list, and consists of the indices of binding constraints at the current iteration. Because this list may not be the solution list, the list is modified either by adding another constraint to the list or by removing one from the list. Geometrically, the active set method tends to step around the boundary defined by the inequality constraints. See Nash and Sofer (1988).

where C_{12} is the transmission capacity of the network before the expansion, C_{12}^{+} is the transmission capacity of the network after the expansion, and b_{12} is the investor preference. The first order conditions of the lower maximization problem can then be added as constraints to the upper problem:

$$
\begin{aligned}
&\underset{a,\hat{t},\delta_{12},\lambda}{Max}\ b_{12}a\delta_{12}\\
&s.t.\\
&T_{12}+a\delta_{12}\le C_{12}^{+}\\
&T_{12}+\hat{t}\delta_{12}+a\delta_{12}\le C_{12}^{+}\\
&p_{12}\delta_{12}-\lambda\delta_{12}=0\\
&\lambda(C_{12}-T_{12}-\hat{t}\delta_{12})=0\\
&T_{12}+\hat{t}\delta_{12}\le C_{12}\\
&\delta_{12}^{2}=1\\
&a,\lambda\ge 0
\end{aligned}
\tag{8.30}
$$

Since the grid is being expanded, the constraint on simultaneous feasibility of incremental FTRs $T_{12}+a\delta_{12}\le C_{12}^{+}$ is non-binding. The solution to this problem provides the values for the decision variables, and shadow prices[123] $\delta_{12}=1$, because the network is being expanded. Additionally, $\gamma=b_{12}$, which implies that the higher the value of the investor-preference parameter b_{12} the more the investor values post-expansion transmission capacity (its marginal valuation of transmission capacity increases with the bid value).

Similarly, we get $\lambda=p_{12}$ which implies that the higher the value of the preset proxy preference parameter p_{12} the higher marginal valuation of pre-expansion transmission capacity. Other results are $\theta=0$, $\zeta=\gamma/p_{12}=b_{12}/p_{12}$ and $\varepsilon=0$. This was expected since only one restriction for the lower problem is binding because the two other are redundant. The value of the binding Lagrange multiplier equals the ratio between the investor's bid value and the preset proxy parameter.

It also follows that $\varphi=0$ which is to be expected because the directional vector δ is non-zero. Furthermore, $\hat{t}=C_{12}-T_{12}$, which means that for given existing rights the higher the current capacity the larger the need for reserving some proxy FTRs for possible negative externalities generated by the expansion. Proxy awards are auctioned as a hedge against externalities generated by the expanded network.

We finally get $a=C_{12}^{+}-T_{12}-\hat{t}=C_{12}^{+}-C_{12}$, which shows that the optimal amount of additional MWs of FTRs in direction δ directly depends on the amount of capacity expansion. Transmission capacity is fully utilized by proxy awards (in the pre-expansion network), and by incremental FTRs (in the expanded network). Likewise, the investor receives a reward equal to the MW amount of new transmission capacity that it creates.

[123] The mathematical derivation of these values is presented in the appendix.

8.4.2 Three-node network with expansion of one of the links

We can now consider a three-node network example from Hogan (2002a) where there is an expansion of line 1-3. The network is illustrated in Figure 8-2 and the feasible expansion FTR set in Figure 8-3.

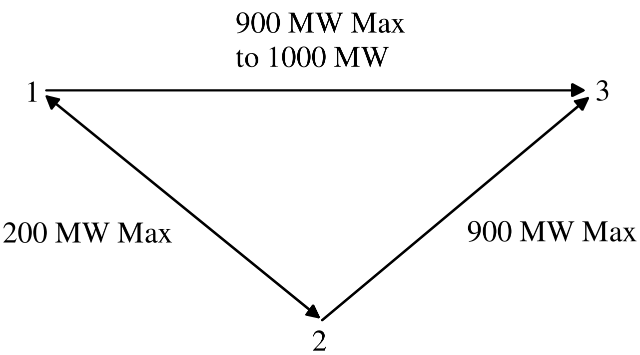

Figure 8-2. Three-node network with expansion in one line.

The expansion problem for a three-node network with identical links and FTRs between buses 1-3 and 2-3 (we assume no mitigating FTRs) is formulated as:

$$
\begin{aligned}
&\underset{a,\delta,\hat{t}}{Max}\ \ a(b_{13}\delta_{13}+b_{23}\delta_{23})\\
&s.t.\\
&\frac{2}{3}(T_{13}+a\delta_{13})+\frac{1}{3}(T_{23}+a\delta_{23})\le C_{13}^{+}\\
&\frac{2}{3}(T_{13}+\hat{t}\delta_{13}+a\delta_{13})+\frac{1}{3}(T_{23}+\hat{t}\delta_{23}+a\delta_{23})\le C_{13}^{+}\\
&\frac{1}{3}(T_{13}+a\delta_{13})+\frac{2}{3}(T_{23}+a\delta_{23})\le C_{23}\\
&\frac{1}{3}(T_{13}+\hat{t}\delta_{13}+a\delta_{13})+\frac{2}{3}(T_{23}+\hat{t}\delta_{23}+a\delta_{23})\le C_{23}\\
&\frac{1}{3}(T_{13}+a\delta_{13})-\frac{1}{3}(T_{23}+a\delta_{23})\le C_{12}\\
&\frac{1}{3}(T_{13}+\hat{t}\delta_{13}+a\delta_{13})-\frac{1}{3}(T_{23}+\hat{t}\delta_{23}+a\delta_{23})\le C_{12}\\
&-\frac{1}{3}(T_{13}+a\delta_{13})+\frac{1}{3}(T_{23}+a\delta_{23})\le C_{21}\\
&-\frac{1}{3}(T_{13}+\hat{t}\delta_{13}+a\delta_{13})+\frac{1}{3}(T_{23}+\hat{t}\delta_{23}+a\delta_{23})\le C_{21}\\
&\hat{t}(\delta)\in \arg\max_{t}\{\ t(p_{13}\delta_{13}+p_{23}\delta_{23})\}\\
&s.t.\\
&\frac{2}{3}(T_{13}+t\delta_{13})+\frac{1}{3}(T_{23}+t\delta_{23})\le C_{13}
\end{aligned}
\tag{8.31}
$$

$$\frac{1}{3}(T_{13}+t\delta_{13})+\frac{2}{3}(T_{23}+t\delta_{23})\le C_{23}$$
$$\frac{1}{3}(T_{13}+t\delta_{13})-\frac{1}{3}(T_{23}+t\delta_{23})\le C_{12}$$
$$-\frac{1}{3}(T_{13}+t\delta_{13})+\frac{1}{3}(T_{23}+t\delta_{23})\le C_{21}$$
$$\|\delta\|=1$$
$$a\ge 0$$

The numerical factors (i.e. 1/3 and 2/3) in the power flow constraints are the power transfer distribution factors (PTDFs) and the appendix shows how to calculate them. In Figure 8-3 the pre-existing FTRs in the direction 1-3 do not use the full capacity of the pre-expansion network. The preference is for FTRs in the direction 1-3 for transmission expansion and the proxy FTRs use the "rest" of the capacity in the existing network. As seen from Figure 8-3 the maximum amount of proxy and incremental FTRs in the direction 1-3 that can be obtained is 1200, and corresponds to the point where the 1-3 and 1-2 transmission capacity constraints intersect.

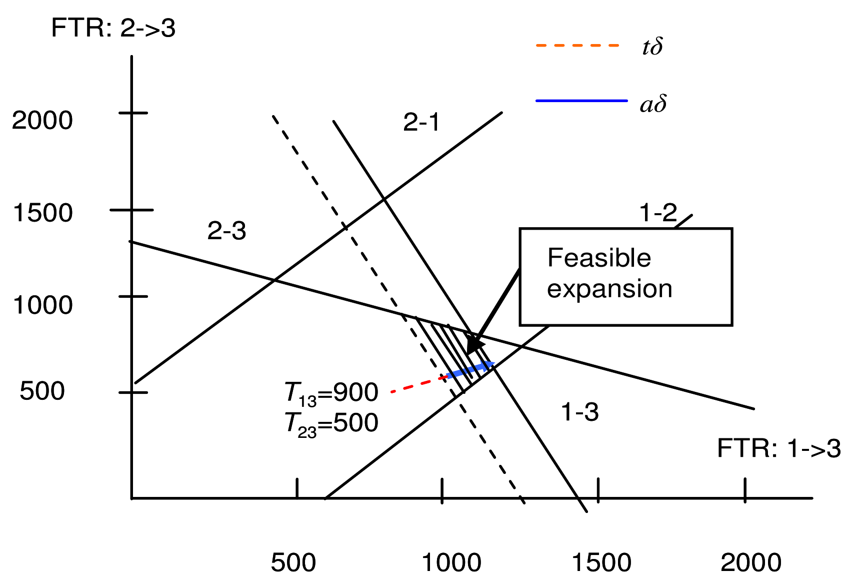

Figure 8-3. Feasible expansion FTR set.

In solving this problem, we get:[124]

[124] The detailed mathematical derivation of solutions to program Equation (8.31) is presented in the appendix.

$$\delta_{13} = \frac{(-1/3\gamma_1 + 1/3\zeta\lambda + 1/3\gamma_2)}{\begin{bmatrix}(-2/3\gamma_1 + 2/3\zeta\lambda - 1/3\gamma_2)^2 \\ +(-1/3\gamma_1 + 1/3\zeta\lambda + 1/3\gamma_2)^2\end{bmatrix}^{1/2}}, \tag{8.32}$$

$$\delta_{23} = \frac{-(-2/3\gamma_1 + 2/3\zeta\lambda - 1/3\gamma_2)}{\begin{bmatrix}(-2/3\gamma_1 + 2/3\zeta\lambda - 1/3\gamma_2)^2 \\ +(-1/3\gamma_1 + 1/3\zeta\lambda + 1/3\gamma_2)^2\end{bmatrix}^{1/2}}$$

$$\hat{t} = \frac{(3C_{13} - 2T_{13} - T_{23})}{\gamma_2} \cdot \Big[(-2/3\gamma_1 + 2/3\zeta\lambda - 1/3\gamma_2)^2 \tag{8.33}$$
$$+(-1/3\gamma_1 + 1/3\xi\lambda + 1/3\gamma_2)^2\Big]^{1/2}$$

$$a = \frac{3(C_{13}^{+} - C_{13})}{\gamma_2} \cdot \Big[(-2/3\gamma_1 + 2/3\zeta\lambda - 1/3\gamma_2)^2 \tag{8.34}$$
$$+(-1/3\gamma_1 + 1/3\xi\lambda + 1/3\gamma_2)^2\Big]^{1/2}$$

$$\gamma_1 = \frac{3}{2(2C_{12} - C_{13}^{+} + T_{23})}\Big[2(1/3b_{13} - 2/3b_{23})$$
$$\cdot\left(\frac{(C_{12} - 1/3T_{13} + 1/3T_{23})}{(C_{13}^{+} - 2/3T_{13} - 1/3T_{23})}\right) + \frac{2(b_{13} + b_{23})}{3} - b_{13}\Big] \tag{8.35}$$
$$\Big[\frac{2(C_{13} - 2/3T_{13} - 1/3T_{23})(C_{12} - 1/3T_{13} + 1/3T_{23})}{(C_{13}^{+} - 2/3T_{13} - 1/3T_{23})}$$
$$-(C_{13}^{+} - 2/3T_{13} - 1/3T_{23})\Big] + \frac{3b_{13}}{2},$$

$$\gamma_2 = \frac{3(C_{13}^{+} - C_{13})}{(2C_{12} - C_{13}^{+} + T_{23})}\Big[\big(2(1/3b_{13} - 2/3b_{23})\cdot \tag{8.36}$$
$$\left(\frac{(C_{12} - 1/3T_{13} + 1/3T_{23})}{(C_{13}^{+} - 2/3T_{13} - 1/3T_{23})}\right) + \frac{2(b_{13} + b_{23})}{3} - b_{13}\Big]$$

$$\zeta\lambda = \gamma_1 + \frac{(C_{12} - 1/3T_{13} + 1/3T_{23})}{(C_{13}^{+} - 2/3T_{13} - 1/3T_{23})} \cdot \gamma_2 \tag{8.37}$$

where γ_1 and γ_2 are the Lagrange multipliers associated with transmission capacity on the lines 1-3 and 1-2, respectively, in the expanded network, and ζ is the multiplier associated with the Kuhn-Tucker condition regarding transmission capacity in the pre-expansion network for the line 1-3. This line has the Lagrange multiplier λ associated with it before expansion. So as to characterize the solution to the model, we now calculate the Lagrange multipliers and decision variables for particular parameter values. In particular, the solution for the allocation presented in Figure 8-3 is found and the following parameters are assumed: bid values, preset proxy preferences and pre-existing amount of FTRs:

$$b_{13}=60,\ b_{23}=10,$$
$$p_{13}=70,\ p_{23}=10,$$
$$T_{13}=900,\ T_{23}=500$$

From these parameters the marginal value of transmission capacity on line 1-3 and line 1-2 is found to be $\gamma_1=76.53$ and $\gamma_2=17.14$, respectively. Thus, the investor values transmission capacity on line 1-3 more than on line 1-2. We find that the product of the Kuhn-Tucker multiplier and the transmission capacity multiplier for the line 1-3 is $\zeta\lambda=81.43$.

Likewise, the values of the decision variables are calculated as:

$$\delta_{13}=0.949,\ \delta_{23}=0.316$$
$$\hat{t}=180.71,\ a=135.5$$

The MW amount of awarded proxy FTRs in the direction 1-3 is $\hat{t}\delta_{13}=171.5$, and the amount of awarded incremental FTRs is $a\delta_{13}=128.6$. Similarly, the amount of proxy awards in direction 2-3 is $\hat{t}\delta_{23}=57.1$, and the amount of awarded incremental FTRs is $a\delta_{23}=42.9$. The solution is indicated by the red and blue lines in Figure 8-3 and consists of both pre-existing, proxy and incremental FTR awards amounting to $T_{13}+\hat{t}\delta_{13}+a\delta_{13}=1200$ and $T_{23}+\hat{t}\delta_{23}+a\delta_{23}=600$. The allocation of incremental FTRs is maximized because the model takes into account that line 1-3 is expanded.

Both the proxy and incremental FTRs exhaust transmission capacity in the pre-expansion and expanded grid, respectively. The proxy FTRs help allocating incremental FTRs by preserving capacity in the pre-expansion network, which results in an allocation of incremental FTRs amounting to the new transmission capacity created.[125] The proxy awards are transmission congestion hedges that can be auctioned to electricity market players in the expanded network.[126]

8.4.3 Three-node network with two parallel links in one of the interfaces after the expansion

We can now turn to the same three-node network as in the preceding section where there is an expansion of interface 2-3 with a second link. The network is illustrated in Figure 8-4 and the feasible expansion FTR set in Figure 8-5.

[125] The new capacity created is defined by the scalar amount of incremental awards times the directional vector.

[126] Whenever there is an institutional restriction to issue LTFTRs there will be an additional (expected congestion) constraint to the model. A proxy for the shadow price of such a constraint would be reflected by the preferences of the investor that carries out the expansion project (assuming risk neutrality and a price taking behavior). The proxy award model takes the "linear" incremental and proxy FTR trajectories to the after-expansion equilibrium point in the ex-post FTR feasible set to ensure the minimum shadow value of the constraint.

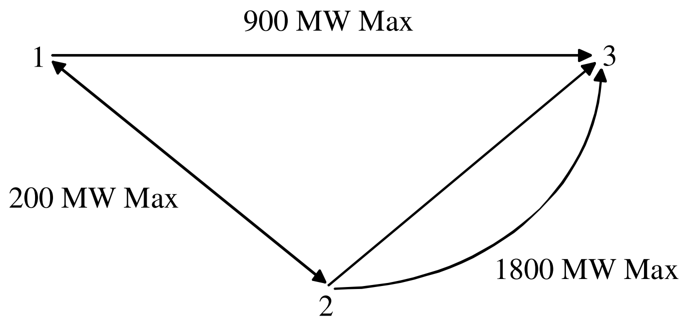

Figure 8-4. Three-node network with expansion of one of the interfaces.

The network expansion problem for identical links and FTRs between buses 1-3 and 2-3 is formulated as:

$$
\begin{aligned}
&\underset{a,\delta,\hat{t}}{Max}\ \ a(b_{13}\delta_{13}+b_{23}\delta_{23})\\
&s.t.\\
&0.6(T_{13}+a\delta_{13})+0.2(T_{23}+a\delta_{23})\le C_{13}\\
&0.6(T_{13}+\hat{t}\,\delta_{13}+a\delta_{13})+0.2(T_{23}+\hat{t}\,\delta_{23}+a\delta_{23})\le C_{13}\\
&0.4(T_{13}+a\delta_{13})+0.8(T_{23}+a\delta_{23})\le C_{23}^{+}\\
&0.4(T_{13}+\hat{t}\,\delta_{13}+a\delta_{13})+0.8(T_{23}+\hat{t}\,\delta_{23}+a\delta_{23})\le C_{23}^{+}\\
&0.4(T_{13}+a\delta_{13})-0.2(T_{23}+a\delta_{23})\le C_{12}\\
&0.4(T_{13}+\hat{t}\,\delta_{13}+a\delta_{13})-0.2(T_{23}+\hat{t}\,\delta_{23}+a\delta_{23})\le C_{12}\\
&-0.4(T_{13}+a\delta_{13})+0.2(T_{23}+a\delta_{23})\le C_{21}\\
&-0.4(T_{13}+\hat{t}\,\delta_{13}+a\delta_{13})+0.2(T_{23}+\hat{t}\,\delta_{23}+a\delta_{23})\le C_{21}\\
&\hat{t}(\delta)\in \arg\max_{t}\left\{\ t(\,p_{13}\delta_{13}+p_{23}\delta_{23})\right\}\\
&s.t.\\
&\frac{2}{3}(T_{13}+t\delta_{13})+\frac{1}{3}(T_{23}+t\delta_{23})\le C_{13},\\
&\frac{1}{3}(T_{13}+t\delta_{13})+\frac{2}{3}(T_{23}+t\delta_{23})\le C_{23},\\
&\frac{1}{3}(T_{13}+t\delta_{13})-\frac{1}{3}(T_{23}+t\delta_{23})\le C_{12},\\
&-\frac{1}{3}(T_{13}+t\delta_{13})+\frac{1}{3}(T_{23}+t\delta_{23})\le C_{21},\\
&\|\delta\|=1,\\
&a\ge 0
\end{aligned}
\tag{8.38}
$$

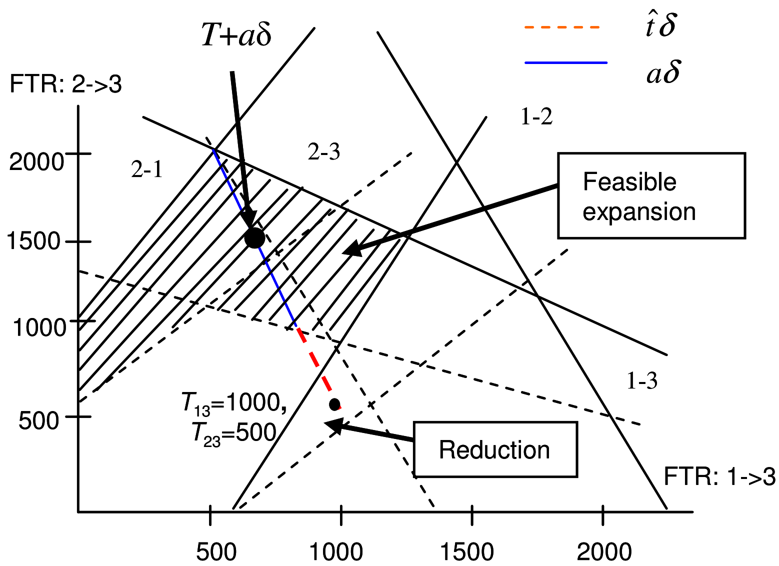

Figure 8-5. Feasible expansion FTR set.

The insertion of a new link in the interface 2-3 changes the impedances and the flow throughout the network and this expands and contracts the set of feasible FTRs as illustrated in Figure 8-5. The pre-existing FTRs do not use the full capacity of the pre-expansion network. The preference is for FTRs in the direction 2-3 for transmission expansion and the proxy FTRs use the "rest" of the capacity in the existing network. As seen from Figure 8-5 the maximum amount of proxy and incremental FTRs in the direction 2-3 that can be obtained is 2000, and corresponds to the point where the 2-1 and 2-3 transmission capacity constraints intersect.

In solving this problem, we get:[127]

$$\delta_{13} = \frac{-(-0.8\gamma_3 + 2/3\psi\eta - 0.2\gamma_4)}{\begin{bmatrix}(-0.8\gamma_3 + 2/3\psi\eta - 0.2\gamma_4)^2 \\ +(-0.4\gamma_3 + 1/3\psi\eta + 0.4\gamma_4)^2\end{bmatrix}^{1/2}}, \qquad (8.39)$$

$$\delta_{23} = \frac{(-0.4\gamma_3 + 1/3\psi\eta + 0.4\gamma_4)}{\begin{bmatrix}(-0.8\gamma_3 + 2/3\psi\eta - 0.2\gamma_4)^2 \\ +(-0.4\gamma_3 + 1/3\psi\eta + 0.4\gamma_4)^2\end{bmatrix}^{1/2}}$$

$$\hat{t} = \frac{(3C_{23} - T_{13} - 2T_{23})}{\gamma_4} \cdot \qquad (8.40)$$

$$\begin{bmatrix}(-0.8\gamma_3 + 2/3\psi\eta - 0.2\gamma_4)^2 \\ +(-0.4\gamma_3 + 1/3\psi\eta + 0.4\gamma_4)^2\end{bmatrix}^{1/2}$$

[127] The detailed mathematical derivation of solutions to program Equation (8.38) is presented in the appendix.

$$a = \frac{(C_{23}^{+} - 1.2C_{23})}{0.4\gamma_4} \cdot \begin{bmatrix} (-0.8\gamma_3 + 2/3\psi\eta - 0.2\gamma_4)^2 \\ +(-0.4\gamma_3 + 1/3\psi\eta + 0.4\gamma_4)^2 \end{bmatrix}^{1/2} \tag{8.41}$$

$$\gamma_3 = 2.5\left[\frac{(b_{23} - 2b_{13})}{\left(\frac{(C_{23}^{+} - 1.2C_{23})}{(1.2C_{23} - 0.4T_{13} - 0.8T_{23})} + 1\right)} \cdot \left\{\frac{(C_{21} + 0.4T_{13} - 0.2T_{23})}{(2.5C_{23}^{+} - T_{13} - 2T_{23})} - \frac{0.1(C_{23}^{+} - 1.2C_{23})}{(1.2C_{23} - 0.4T_{13} - 0.8T_{23})} - 0.1\right\}\right] + 1.25b_{23} \tag{8.42}$$

$$\gamma_4 = \frac{\frac{(C_{23}^{+} - 1.2C_{23})}{(1.2C_{23} - 0.4T_{13} - 0.8T_{23})}(b_{23} - 2b_{13})}{\left(\frac{(C_{23}^{+} - 1.2C_{23})}{(1.2C_{23} - 0.4T_{13} - 0.8T_{23})} + 1\right)} \tag{8.43}$$

$$\psi\eta = 1.2\left(\frac{(C_{23}^{+} - 1.2C_{23})}{(1.2C_{23} - 0.4T_{13} - 0.8T_{23})} + 1\right) \cdot (\gamma_3 - \gamma_4) - \frac{(C_{23}^{+} - 1.2C_{23})3b_{13}}{(1.2C_{23} - 0.4T_{13} - 0.8T_{23})} \tag{8.44}$$

where γ_3 and γ_4 are the Lagrange multipliers associated with transmission capacity on the lines 2-3 and 2-1 in the expanded network, respectively. ψ is the multiplier associated with the Kuhn-Tucker condition of transmission capacity in the pre-expansion network for line 2-3. This line has the Lagrange multiplier η associated with it before expansion. So as to characterize the solution to the model, we now calculate the Lagrange multipliers and decision variables for particular parameter values. In particular, the solution for the allocation presented in Figure 8-5 is found and the following parameters are assumed: bid values, preset proxy preferences and pre-existing amount of FTRs:

$$b_{13} = 10,\ b_{23} = 60,$$
$$p_{13} = 10,\ p_{23} = 60,$$
$$T_{13} = 1000,\ T_{23} = 500$$

From these parameters the marginal value of transmission capacity on line 2-3 and line 2-1 is found to be $\gamma_3 = 70.6$ and $\gamma_4 = 28.8$, respectively. Thus the investor values transmission capacity on line 2-3 more than on line 2-1. We find that the product of the Kuhn-Tucker multiplier and the transmission capacity multiplier for the line 2-3 is $\psi\eta = 102$.

Likewise, the values of the decision variables are calculated as:

$\delta_{13} = -0.316,\ \delta_{23} = 0.949$
$\hat{t} = 442.72,\ a = 1138.42$

The MW amount of awarded proxy FTRs in the direction 1-3 is $\hat{t}\delta_{13} = -139.9$, and the amount of awarded incremental FTRs is $a\delta_{13} = -359.74$. Similarly, the amount of proxy awards in direction 2-3 is $\hat{t}\delta_{23} = 420.14$, and the amount of awarded incremental FTRs is $a\delta_{23} = 1081.36$. The solution is indicated by the large dot in Figure 8-5 and consists of both pre-existing and incremental FTR awards amounting to $T_{13} + a\delta_{13} = 640.26$ and $T_{23} + a\delta_{23} = 1581.4$. The allocation of incremental 1-3 FTRs is minimized because the model takes into account that line 2-3 is expanded, and some of the pre-existing FTRs become infeasible after the expansion.

8.4.4 Three-node network with two links

We now look at a three-node network example from Bushnell and Stoft (1997) where there is an expansion of line 1-2. The network is illustrated in Figure 8-6 and the feasible expansion FTR set in Figure 8-7

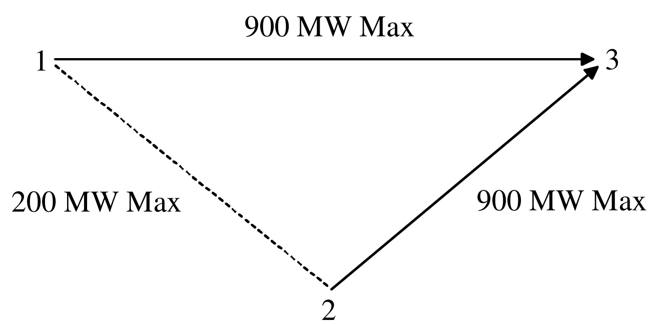

Figure 8-6. Three-node network with expansion of line 1-2.

The network expansion problem for identical links and FTRs between buses 1-3 and 2-3 is formulated as:

$$
\begin{aligned}
&\underset{a,\hat{t},\delta}{Max} \quad a(b_{13}\delta_{13} + b_{23}\delta_{23}) \\
&s.t. \\
&\frac{2}{3}(T_{13} + a\delta_{13}) + \frac{1}{3}(T_{23} + a\delta_{23}) \le C_{13} \\
&\frac{2}{3}(T_{13} + \hat{t}\delta_{13} + a\delta_{13}) + \frac{1}{3}(T_{23} + \hat{t}\delta_{23} + a\delta_{23}) \le C_{13} \\
&\frac{1}{3}(T_{13} + a\delta_{13}) + \frac{2}{3}(T_{23} + a\delta_{23}) \le C_{23} \\
&\frac{1}{3}(T_{13} + \hat{t}\delta_{13} + a\delta_{13}) + \frac{2}{3}(T_{23} + \hat{t}\delta_{23} + a\delta_{23}) \le C_{23} \\
&\frac{1}{3}(T_{13} + a\delta_{13}) - \frac{1}{3}(T_{23} + a\delta_{23}) \le C_{12} \\
&\frac{1}{3}(T_{13} + \hat{t}\delta_{13} + a\delta_{13}) - \frac{1}{3}(T_{23} + \hat{t}\delta_{23} + a\delta_{23}) \le C_{12} \\
&-\frac{1}{3}(T_{13} + a\delta_{13}) + \frac{1}{3}(T_{23} + a\delta_{23}) \le C_{21} \\
&-\frac{1}{3}(T_{13} + \hat{t}\delta_{13} + a\delta_{13}) + \frac{1}{3}(T_{23} + \hat{t}\delta_{23} + a\delta_{23}) \le C_{21} \\
&\hat{t}(\delta) \in \arg\max_{t} \{t(p_{13}\delta_{13} + p_{23}\delta_{23})\} \\
&(T_{13} + t\delta_{13}) \le C_{13} \\
&(T_{23} + t\delta_{23}) \le C_{23} \\
&\|\delta\| = 1 \\
&a \ge 0
\end{aligned}
\tag{8.45}
$$

In Figure 8-7 the pre-existing FTRs in the direction 2-3 do not use the full capacity of the pre-expansion network and become infeasible after inserting line 1-2. The preference is for FTRs in the direction 1-3 for transmission expansion. As seen from Figure 8-7 the maximum amount of proxy and incremental FTRs in the direction 1-3 that can be obtained is 1100, and corresponds to the point where the 1-3 and 1-2 transmission capacity constraints intersect.

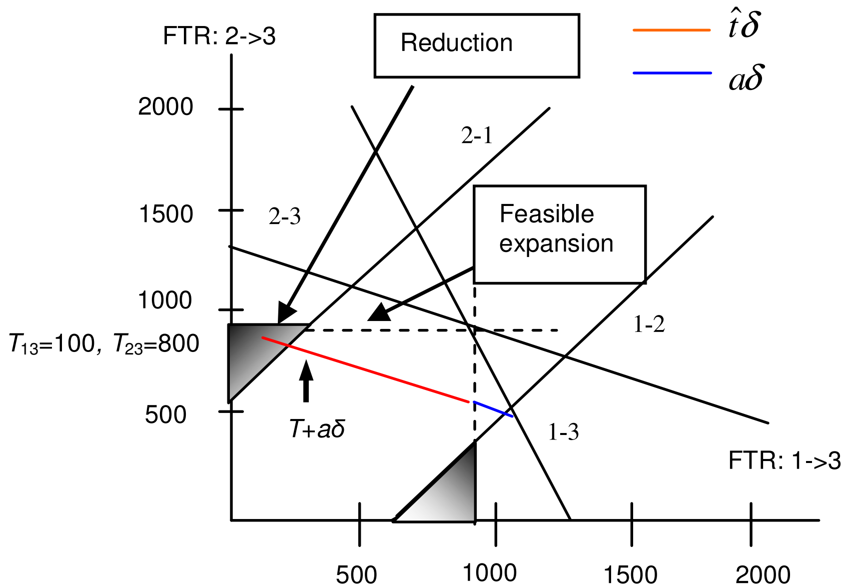

Figure 8-7. Feasible expansion FTR set.

In solving this problem, we get:[128]

$$\delta_{13} = \frac{(1/3\gamma_1 - 1/3\gamma_2)}{\left((2/3\gamma_1 + 1/3\gamma_2 - \zeta\lambda)^2 + (1/3\gamma_1 - 1/3\gamma_2)^2\right)^{1/2}}$$

$$\delta_{23} = \frac{-(2/3\gamma_1 + 1/3\gamma_2 - \zeta\lambda)}{\left((2/3\gamma_1 + 1/3\gamma_2 - \zeta\lambda)^2 + (1/3\gamma_1 - 1/3\gamma_2)^2\right)^{1/2}}$$

$$a = \frac{C_{12}}{\delta_{13}}$$

$$\hat{t} = \frac{(C_{13} - T_{13})}{\delta_{13}}$$

$$\gamma_1 = \frac{(b_{13} + Bb_{23} + \gamma_2(B/3 - 1/3))}{(2/3 + B/3)}$$

$$\gamma_2 = \frac{1}{(1 - B - AB + A)}\left[b_{13}(1 + 3A - B - 2A - AB)\right.$$

$$\left. + b_{23}(B + 3AB - B^2 - 2A - AB)\right]$$

$$\zeta\lambda = (1 + A)\gamma_1 - A(b_{13} + b_{23})$$

with

[128] The detailed mathematical derivation of solutions to program Equation (8.45) is presented in the appendix.

$$A = \frac{C_{12}}{(C_{13} - T_{13})}$$
$$B = \frac{1}{(1+A)} \frac{(C_{13} - 2C_{12} - T_{23})}{(C_{13} - T_{13})}$$

where γ_1 and γ_2 are the Lagrange multipliers associated with transmission capacity on the lines 1-3 and 1-2, respectively, in the expanded network, and ζ is the multiplier associated with the Kuhn-Tucker condition regarding transmission capacity in the pre-expansion network for the line 1-3. This line has the Lagrange multiplier λ associated with it before expansion. So as to characterize the solution to the model, we now calculate the Lagrange multipliers and decision variables for particular parameter values. In particular, the solution for the allocation presented in Figure 8-7 is found and the following parameters are assumed: bid values, preset proxy preferences and pre-existing amount of FTRs:

$$b_{13} = 40,\ b_{23} = 10,$$
$$p_{13} = 60,\ p_{23} = 10,$$
$$T_{13} = 100,\ T_{23} = 800$$

From these parameters we find that the marginal value of transmission capacity on line 1-3 and line 1-2 is $\gamma_1 = 39.6$ and $\gamma_2 = 33.6$, respectively. Thus the investor values transmission capacity on line 1-3 more than on line 1-2. We find that the product of the Kuhn-Tucker multiplier and the transmission capacity multiplier for the line 1-3 is $\zeta\lambda = 37$.

Likewise, the values of the decision variables are calculated as:

$$\delta_{13} = 0.958,\ \delta_{23} = -0.287$$
$$\hat{t} = 835,\ a = 208$$

The MW amount of awarded proxy FTRs in the direction 1-3 is $\hat{t}\delta_{13} = 800$, and the amount of awarded incremental FTRs is $a\delta_{13} = 200$. The amount of incremental 1-3 FTRs corresponds to the new transmission capacity on line 1-2 that the investor has created. There is also an allocation of proxy FTRs such that the full capacity of line 1-3 is utilized. Similarly, the amount of proxy awards in direction 2-3 is $\hat{t}\delta_{23} = -240$, and the amount of awarded incremental FTRs is $a\delta_{23} = -60$. The amount of incremental 2-3 FTRs is minimized and corresponds to 20% of the reduction (300) in pre-existing FTRs. The incremental 2-3 awards are mitigating FTRs, and are necessary to restore feasibility. The investor is responsible for additional counterflows so that it pays back for the negative externalities it creates. The solution is indicated by the black arrow in Figure 8-7 and consists of both pre-existing and incremental FTR awards amounting to $T_{13} + a\delta_{13} = 300$ and $T_{23} + a\delta_{23} = 740$. The allocation of incremental 2-3 FTRs is minimized because the model takes into account that line 1-2 is expanded, and some of the pre-existing FTRs become infeasible after the expansion.

This illustrates that the amount of incremental FTRs in the preference direction must be greater than zero such that feasibility is restored. Both the proxy and incremental FTRs exhaust transmission capacity in the pre-expansion and expanded grid, respectively. The proxy FTRs help allocating incremental FTRs by preserving capacity in the pre-expansion network, which results in an allocation of incremental FTRs amounting to the new transmission capacity created in 1-2 direction.[129]

In the example provided by Bushnell and Stoft (1997), the investor with pre-existing FTRs chooses the most profitable incremental FTR based on optimizing its final benefit. The investor is then awarded a mitigating incremental 1-2 FTR with associated power flows corresponding to the difference between the ex-ante and ex-post optimal dispatches. The pre-existing FTRs correspond to the actual dispatch of the system and become infeasible after expanding line 1-2, and therefore a mitigating 1-2 FTR[130] is allocated so that feasibility is exactly restored (that is, the investor "pays back" for the negative externalities to other agents). There is no allocation of proxy awards because the pre-expansion network is fully allocated by FTRs before the expansion. The amount of incremental FTRs is minimized because they represent a negative value to the investor and decrease its revenues from the pre-existing FTRs.

Bushnell and Stoft (1997) demonstrate that the increase in social welfare will be at least as large as the ex-post value of new contracts, when the FTRs initially match dispatch in the aggregate and new FTRs are allocated according to the feasibility rule. In particular, if social welfare is decreased by a transmission expansion, the investor will have to take FTRs with a negative value (If social welfare is increased there will be free riding). Some agents might still benefit from investments that reduce social welfare, whenever their own commercial interests improve to an extent that more than offsets the negative value of the new FTRs. This problem can be solved if it is required that FTRs are used by each agent as a perfect hedge for their net load. In such a case, FTRs allocated under the feasibility rule ensure that no one will benefit from an expansion that reduces welfare.

The proxy award mechanism implies nonnegative effects on welfare in the sense that future investments in the grid cannot reduce the welfare of aggregate use for FTR holders. The reason is that simultaneous feasibility is guaranteed before and after the enhancement project so that revenue adequacy is also guaranteed after expansion. Only those non-hedged agents in the spot market might be exposed to rent transfers. Therefore, the proxy award mechanism presented in this chapter emphasizes the value of hedging.

Although apparently similar, the mechanism and its implications on welfare are rather different to those in the Bushnell and Stoft (1997) model. Bushnell and Stoft analyze the welfare implications of transmission expansion given match of dispatch both in the aggregate and individually. In our model, it is assumed unallocated FTRs both before and after the expansion, so that there is no match of dispatch.

[129] Note that this result will depend on the network interactions. In some cases the amount of incremental FTRs in the preference direction will differ from the new capacity created on a specific line. However, it will always amount to the new capacity created as defined by the scalar amount of incremental FTRs times the directional vector.

[130] The incremental 1-2 FTR can be decomposed into a 1-3 FTR and a 3-2 FTR

Additionally, Bushnell and Stoft explicitly define loads, locational prices, and generation costs so that the effects on welfare are measured as the change in net generation costs. In contrast, this work does not define a net benefit function of the users of the grid in terms of prices, generation costs or income from loads. Alternatively, the presented model maximizes the investors' objective function in terms of incremental FTRs.

8.5 Concluding remarks

A merchant mechanism is proposed to expand electricity transmission. Proxy awards (or reserved FTRs) are a fundamental part of this mechanism. They have been defined according to the best use of the current network along the same direction of the incremental expansion. The incremental FTR awards are allocated according to the investor preferences, and depend on the initial partial allocation of FTRs and network topology before and after expansion.

The examples used showed that the internalization of possible negative externalities caused by potential expansion is possible according to the rule proposed by Hogan (2002a): allocation of FTRs before (proxy FTRs) and after (incremental FTRs) the expansion is in the same direction and according to the feasibility rule. Under these circumstances, the investor will have the proper incentives to invest in transmission expansion in its preference direction given by its bid parameters. Likewise, the larger the existing current capacity the greater the number of FTRs that must be reserved in order to deal with potential negative externalities depending on post network topology.

The mechanism of long-term FTRs is basically a way to hedge market players from long-run nodal price fluctuations by providing them with the necessary property transmission rights. The main purpose of the four basic axioms that support our model (*feasibility rule*, *proxy awards*, *maximum value* and *symmetry*) were to define property rights for increased transmission investment according to the preset proxy rule. However, the general implications on welfare and incentives for gaming are still an open research question. Another "axiom" might be needed to deal with these last issues.

Although this model is specifically designed to deal with loop flows, and the security-constrained version of the model can take care of contingency concerns, this proposed mechanism is to be applied to expansions where the locational price difference does not vanish totally. LTFTRs are efficient under non-lumpy marginal expansions of the transmission network, and lack of market power. Regulation has then an important complementary role in fostering large and lumpy projects where investment is large relative to market size, and in mitigating market power. Since revenues from nodal prices only recover a small part of total costs, LTFTRs must be complemented with a regulated framework that allows the recovery of fixed costs. The challenge is to effectively combine merchant and regulated transmission investments or, as Hogan (2003) puts it, to establish a rule in practice for drawing a line between merchant and regulated investments.

Appendix

Solution of program Equation (8.29)

The Lagrangian of the problem is:

$$L(a,\hat{t},\delta_{12},\lambda,\Omega)=b_{12}a\delta_{12}+\gamma(C_{12}^{+}-T_{12}-(a+\hat{t})\delta_{12})$$
$$-\theta(p_{12}\delta_{12}-\lambda\delta_{12})-\zeta(\lambda(C_{12}-T_{12}-\hat{t}\delta_{12}))$$
$$+\varepsilon(C_{12}-T_{12}-\hat{t}\delta_{12})+\varphi(1-\delta_{12}^{2})+\kappa a+\pi\lambda \tag{8.46}$$

where $\gamma,\theta,\zeta,\varepsilon,\varphi,\kappa,$ and π are the multipliers associated with the respective constraints.

At optimality the Kuhn-Tucker conditions are:

$$\frac{\partial L(a,\hat{t},\delta_{12},\lambda,\Omega)}{\partial a}=b_{12}\delta_{12}-\gamma\delta_{12}=0, \tag{8.47}$$

$$\frac{\partial L(a,\hat{t},\delta_{12},\lambda,\Omega)}{\partial \delta_{12}}=ab_{12}-(\hat{t}+a)\gamma-(p_{12}-\lambda)\theta \tag{8.48}$$

$$+\lambda\zeta\hat{t}-\varepsilon\hat{t}-2\delta_{12}\varphi=0,$$

$$\frac{\partial L(a,\hat{t},\delta_{12},\lambda,\Omega)}{\partial \hat{t}}=-\gamma\delta_{12}+\lambda\zeta\delta_{12}-\varepsilon\delta_{12}=0, \tag{8.49}$$

$$\frac{\partial L(a,\hat{t},\delta_{12},\lambda,\Omega)}{\partial \lambda}=\delta_{12}\theta-(C_{12}-T_{12}-\hat{t}\delta_{12})\zeta=0, \tag{8.50}$$

$$\frac{\partial L(a,\hat{t},\delta_{12},\lambda,\Omega)}{\partial \gamma}=(C_{12}^{+}-T_{12}-(a+\hat{t})\delta_{12})=0, \tag{8.51}$$

$$\frac{\partial L(a,\hat{t},\delta_{12},\lambda,\Omega)}{\partial \theta}=-(p_{12}\delta_{12}-\lambda\delta_{12})=0, \tag{8.52}$$

$$\frac{\partial L(a,\hat{t},\delta_{12},\lambda,\Omega)}{\partial \zeta}=-\lambda(C_{12}-T_{12}-\hat{t}\delta_{12})=0, \tag{8.53}$$

$$\frac{\partial L(a,\hat{t},\delta_{12},\lambda,\Omega)}{\partial \varepsilon}=(C_{12}-T_{12}-\hat{t}\delta_{12})=0, \tag{8.54}$$

$$\frac{\partial L(a,\hat{t},\delta_{12},\lambda,\Omega)}{\partial \varphi}=(1-\delta_{12}^{2})=0, \tag{8.55}$$

$$\frac{\partial L(a,\hat{t},\delta_{12},\lambda,\Omega)}{\partial \kappa}=a>0,\ \kappa=0, \tag{8.56}$$

$$\frac{\partial L(a,\hat{t},\delta_{12},\lambda,\Omega)}{\partial \pi}=\lambda>0,\ \pi=0, \tag{8.57}$$

$$\gamma, \varepsilon \geq 0 \tag{8.58}$$

Equation (8.55) gives $\delta_{12} = 1$. Equation (8.47) gives $\gamma = b_{12}$. Equation (8.52) gives $\lambda = p_{12}$, Equation (8.49) $\zeta = \gamma / p_{12} = b_{12} / p_{12}$ (ε is zero because the constraint is redundant), and Equation (8.50) $\theta = 0$. From this it follows (Equation (8.48)) that $\varphi = 0$ Furthermore Equation (8.53) gives $\hat{t} = C_{12} - T_{12}$. Equation (8.51) implies that $a = C_{12}^{+} - T_{12} - \hat{t} = C_{12}^{+} - C_{12}$.

Solution of program Equation (8.31)

The Lagrangian of the problem is:

$$\begin{aligned}
&L(a,\hat{t},\delta,\lambda,\Omega) = a(b_{13}\delta_{13} + b_{23}\delta_{23}) \\
&+\gamma_1(C_{13}^{+} - \frac{2}{3}(T_{13} + (\hat{t}+a)\delta_{13}) - \frac{1}{3}(T_{23} + (\hat{t}+a)\delta_{23}) \\
&+\gamma_2(C_{12} - \frac{1}{3}(T_{13} + (\hat{t}+a)\delta_{13}) + \frac{1}{3}(T_{23} + (\hat{t}+a)\delta_{23})) \\
&-\zeta(\lambda(C_{13} - \frac{2}{3}(T_{13} + \hat{t}\delta_{13}) - \frac{1}{3}(T_{23} + \hat{t}\delta_{23}))) \\
&+\varepsilon(C_{13} - \frac{2}{3}(T_{13} + \hat{t}\delta_{13}) - \frac{1}{3}(T_{23} + \hat{t}\delta_{23})) + \varphi(1 - \delta_{13}^2 - \delta_{23}^2) + \kappa a + \pi\lambda
\end{aligned} \tag{8.59}$$

where γ_1 and γ_2 are the Lagrange multipliers associated with transmission capacity on the lines 1-3 and 1-2 in the expanded network, respectively. ζ is the multiplier associated with the Kuhn-Tucker condition of transmission capacity in the pre-expansion network for line 1-3. This line has the Lagrange multiplier λ associated with it before expansion. ε is the investor's marginal value of transmission capacity in the pre-expansion network when allocating incremental FTRs. The normalization condition has the multiplier φ and the non-negativity conditions have the associated multipliers κ and π. The first order conditions are:

$$\begin{aligned}
&\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial a} = (b_{13}\delta_{13} + b_{23}\delta_{23}) - (\frac{2}{3}\delta_{13} + \frac{1}{3}\delta_{23})\gamma_1 \\
&-(\frac{1}{3}\delta_{13} - \frac{1}{3}\delta_{23})\gamma_2 = 0,
\end{aligned} \tag{8.60}$$

$$\begin{aligned}
&\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \delta_{13}} = ab_{13} - \frac{2}{3}(\hat{t}+a)\gamma_1 - \frac{1}{3}(\hat{t}+a)\gamma_2 \\
&+\frac{2}{3}\zeta\lambda\hat{t} - \frac{2}{3}\varepsilon\hat{t} - 2\varphi\delta_{13} = 0,
\end{aligned} \tag{8.61}$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \delta_{23}} = ab_{23} - \frac{1}{3}(\hat{t}+a)\gamma_1 + \frac{1}{3}(\hat{t}+a)\gamma_2 \tag{8.62}$$

$$+\frac{1}{3}\zeta\lambda\hat{t} - \frac{1}{3}\varepsilon\hat{t} - 2\varphi\delta_{23} = 0,$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \hat{t}} = -(\frac{2}{3}\delta_{13} + \frac{1}{3}\delta_{23})\gamma_1 - (\frac{1}{3}\delta_{13} - \frac{1}{3}\delta_{23})\gamma_2 \tag{8.63}$$

$$+(\frac{2}{3}\delta_{13} + \frac{1}{3}\delta_{23})\zeta\lambda - (\frac{2}{3}\delta_{13} + \frac{1}{3}\delta_{23})\varepsilon = 0,$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \lambda} = -\zeta(C_{13} - \frac{2}{3}(T_{13} + \hat{t}\delta_{13}) \tag{8.64}$$

$$-\frac{1}{3}(T_{23} + \hat{t}\delta_{23})) = 0,$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \gamma_1} = C_{13}^{+} - \frac{2}{3}(T_{13} + (\hat{t}+a)\delta_{13}) \tag{8.65}$$

$$-\frac{1}{3}(T_{23} + (\hat{t}+a)\delta_{23}) = 0,$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \gamma_2} = C_{12} - \frac{1}{3}(T_{13} + (\hat{t}+a)\delta_{13}) \tag{8.66}$$

$$+\frac{1}{3}(T_{23} + (\hat{t}+a)\delta_{23}) = 0,$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \zeta} = -\lambda(C_{13} - \frac{2}{3}(T_{13} + \hat{t}\delta_{13}) \tag{8.67}$$

$$-\frac{1}{3}(T_{23} + \hat{t}\delta_{23})) = 0,$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \varepsilon} = (C_{13} - \frac{2}{3}(T_{13} + \hat{t}\delta_{13}) - \frac{1}{3}(T_{23} + \hat{t}\delta_{23})) = 0, \tag{8.68}$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \varphi} = 1 - \delta_{13}^2 - \delta_{23}^2 = 0, \tag{8.69}$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \kappa} = a > 0,\ \kappa = 0, \tag{8.70}$$

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \pi} = \lambda > 0,\ \pi = 0, \tag{8.71}$$

In this program ε is zero because the constraint is redundant. The solution for the first order conditions is given by:

$$\delta_{13}=\frac{(-1/3\gamma_1+1/3\zeta\lambda+1/3\gamma_2)}{\begin{bmatrix}(-2/3\gamma_1+2/3\zeta\lambda-1/3\gamma_2)^2\\+(-1/3\gamma_1+1/3\zeta\lambda+1/3\gamma_2)^2\end{bmatrix}^{1/2}},$$

$$\delta_{23}=\frac{-(-2/3\gamma_1+2/3\zeta\lambda-1/3\gamma_2)}{\begin{bmatrix}(-2/3\gamma_1+2/3\zeta\lambda-1/3\gamma_2)^2\\+(-1/3\gamma_1+1/3\zeta\lambda+1/3\gamma_2)^2\end{bmatrix}^{1/2}}$$

$$\hat{t}=\frac{(3C_{13}-2T_{13}-T_{23})}{\gamma_2}\cdot\Big[(-2/3\gamma_1+2/3\zeta\lambda-1/3\gamma_2)^2$$
$$+(-1/3\gamma_1+1/3\xi\lambda+1/3\gamma_2)^2\Big]^{1/2}$$

$$a=\frac{3(C_{13}^{+}-C_{13})}{\gamma_2}\cdot\Big[(-2/3\gamma_1+2/3\zeta\lambda-1/3\gamma_2)^2$$
$$+(-1/3\gamma_1+1/3\xi\lambda+1/3\gamma_2)^2\Big]^{1/2}$$

$$\gamma_1=\frac{3}{2(2C_{12}-C_{13}^{+}+T_{23})}\Big[2(1/3b_{13}-2/3b_{23})$$
$$\cdot\left(\frac{(C_{12}-1/3T_{13}+1/3T_{23})}{(C_{13}^{+}-2/3T_{13}-1/3T_{23})}\right)+\frac{2(b_{13}+b_{23})}{3}-b_{13}\Big]$$

$$\Big[\frac{2(C_{13}-2/3T_{13}-1/3T_{23})(C_{12}-1/3T_{13}+1/3T_{23})}{(C_{13}^{+}-2/3T_{13}-1/3T_{23})}$$
$$-(C_{13}^{+}-2/3T_{13}-1/3T_{23})\Big]+\frac{3b_{13}}{2},$$

$$\gamma_2=\frac{3(C_{13}^{+}-C_{13})}{(2C_{12}-C_{13}^{+}+T_{23})}\Big[\big(2(1/3b_{13}-2/3b_{23})\cdot$$
$$\left(\frac{(C_{12}-1/3T_{13}+1/3T_{23})}{(C_{13}^{+}-2/3T_{13}-1/3T_{23})}\right)+\frac{2(b_{13}+b_{23})}{3}-b_{13}\Big]$$

$$\zeta\lambda=\gamma_1+\frac{(C_{12}-1/3T_{13}+1/3T_{23})}{(C_{13}^{+}-2/3T_{13}-1/3T_{23})}\cdot\gamma_2$$

Solution of program Equation (8.38)

The Lagrangian of the problem is:

$$
\begin{aligned}
&L(a,\hat{t},\delta,\eta,\Omega) = a(b_{13}\delta_{13} + b_{23}\delta_{23}) + \\
&+\gamma_3(C_{23}^{+} - 0.4(T_{13} + (\hat{t}+a)\delta_{13}) - 0.8(T_{23} + (\hat{t}+a)\delta_{23}) \\
&+\gamma_4(C_{21} + 0.4(T_{13} + (\hat{t}+a)\delta_{13}) - 0.2(T_{23} + (\hat{t}+a)\delta_{23})) \\
&-\psi(\eta(C_{23} - \frac{1}{3}(T_{13} + \hat{t}\delta_{13}) - \frac{2}{3}(T_{23} + \hat{t}\delta_{23}))) \\
&+\varepsilon_2(C_{23} - \frac{1}{3}(T_{13} + \hat{t}\delta_{13}) - \frac{2}{3}(T_{23} + \hat{t}\delta_{23})) \\
&+\varphi(1 - \delta_{13}^2 - \delta_{23}^2) + \kappa a + \rho\eta
\end{aligned}
\tag{8.72}
$$

where γ_3 and γ_4 are the Lagrange multipliers associated with transmission capacity on the lines 2-3 and 2-1 in the expanded network, respectively. ψ is the multiplier associated with the Kuhn-Tucker condition of transmission capacity in the pre-expansion network for line 2-3. This line has the Lagrange multiplier η associated with it before expansion. ε_2 is the investor's marginal value of transmission capacity on line 2-3 in the pre-expansion network when allocating incremental FTRs. The normalization condition has the multiplier φ and the non-negativity conditions have the associated multipliers κ and ρ. The first order conditions are:

$$
\begin{aligned}
&\frac{\partial L(a,\hat{t},\delta,\eta,\Omega)}{\partial a} = (b_{13}\delta_{13} + b_{23}\delta_{23}) - (0.4\delta_{13} + 0.8\delta_{23})\gamma_3 \\
&-(-0.4\delta_{13} + 0.2\delta_{23})\gamma_4 = 0,
\end{aligned}
\tag{8.73}
$$

$$
\begin{aligned}
&\frac{\partial L(a,\hat{t},\delta,\eta,\Omega)}{\partial \delta_{13}} = ab_{13} - 0.4(\hat{t}+a)\gamma_3 + 0.4(\hat{t}+a)\gamma_4 \\
&+\frac{1}{3}\psi\eta\hat{t} - \frac{1}{3}\varepsilon_2\hat{t} - 2\varphi\delta_{13} = 0,
\end{aligned}
\tag{8.74}
$$

$$
\begin{aligned}
&\frac{\partial L(a,\hat{t},\delta,\eta,\Omega)}{\partial \delta_{23}} = ab_{23} - 0.8(\hat{t}+a)\gamma_3 - 0.2(\hat{t}+a)\gamma_4 \\
&+\frac{2}{3}\psi\eta\hat{t} - \frac{2}{3}\varepsilon_2\hat{t} - 2\varphi\delta_{23} = 0,
\end{aligned}
\tag{8.75}
$$

$$
\begin{aligned}
&\frac{\partial L(a,\hat{t},\delta,\eta,\Omega)}{\partial \hat{t}} = -(0.4\delta_{13} + 0.8\delta_{23})\gamma_3 \\
&-(-0.4\delta_{13} + 0.2\delta_{23})\gamma_4 + (\frac{1}{3}\delta_{13} + \frac{2}{3}\delta_{23})\psi\eta \\
&-(\frac{1}{3}\delta_{13} + \frac{2}{3}\delta_{23})\varepsilon_2 = 0,
\end{aligned}
\tag{8.76}
$$

$$
\begin{aligned}
&\frac{\partial L(a,\hat{t},\delta,\eta,\Omega)}{\partial \eta} = -\psi(C_{23} - \frac{1}{3}(T_{13} + \hat{t}\delta_{13}) \\
&-\frac{2}{3}(T_{23} + \hat{t}\delta_{23})) = 0,
\end{aligned}
\tag{8.77}
$$

$$
\begin{aligned}
&\frac{\partial L(a,\hat{t},\delta,\eta,\Omega)}{\partial \gamma_3} = C_{23}^{+} - 0.4(T_{13} + (\hat{t}+a)\delta_{13}) \\
&-0.8(T_{23} + (\hat{t}+a)\delta_{23}) = 0,
\end{aligned}
\tag{8.78}
$$

$$\frac{\partial L(a,\hat{t},\delta,\eta,\Omega)}{\partial \gamma_4} = C_{21} + 0.4(T_{13} + (\hat{t}+a)\delta_{13}) \tag{8.79}$$

$$-0.2(T_{23} + (\hat{t}+a)\delta_{23}) = 0,$$

$$\frac{\partial L(a,\hat{t},\delta,\eta,\Omega)}{\partial \psi} = -\eta(C_{23} - \frac{1}{3}(T_{13} + \hat{t}\delta_{13}) \tag{8.80}$$

$$-\frac{2}{3}(T_{23} + \hat{t}\delta_{23})) = 0,$$

$$\frac{\partial L(a,\hat{t},\delta,\eta,\Omega)}{\partial \varepsilon_2} = (C_{13} - \frac{2}{3}(T_{13} + \hat{t}\delta_{13}) - \frac{1}{3}(T_{23} + \hat{t}\delta_{23})) = 0, \tag{8.81}$$

$$\frac{\partial L(a,\hat{t},\delta,\eta,\Omega)}{\partial \varphi} = 1 - \delta_{13}^2 - \delta_{23}^2 = 0, \tag{8.82}$$

$$\frac{\partial L(a,\hat{t},\delta,\eta,\Omega)}{\partial \kappa} = a > 0, \ \kappa = 0, \tag{8.83}$$

$$\frac{\partial L(a,\hat{t},\delta,\eta,\Omega)}{\partial \rho} = \eta > 0, \ \rho = 0, \tag{8.84}$$

The solution for the first order conditions is given by:

$$\delta_{13} = \frac{-(-0.8\gamma_3 + 2/3\psi\eta - 0.2\gamma_4)}{\begin{bmatrix} (-0.8\gamma_3 + 2/3\psi\eta - 0.2\gamma_4)^2 \\ +(-0.4\gamma_3 + 1/3\psi\eta + 0.4\gamma_4)^2 \end{bmatrix}^{1/2}},$$

$$\delta_{23} = \frac{(-0.4\gamma_3 + 1/3\psi\eta + 0.4\gamma_4)}{\begin{bmatrix} (-0.8\gamma_3 + 2/3\psi\eta - 0.2\gamma_4)^2 \\ +(-0.4\gamma_3 + 1/3\psi\eta + 0.4\gamma_4)^2 \end{bmatrix}^{1/2}}$$

$$\hat{t} = \frac{(3C_{23} - T_{13} - 2T_{23})}{\gamma_4} \cdot$$

$$\begin{bmatrix} (-0.8\gamma_3 + 2/3\psi\eta - 0.2\gamma_4)^2 \\ +(-0.4\gamma_3 + 1/3\psi\eta + 0.4\gamma_4)^2 \end{bmatrix}^{1/2}$$

$$a = \frac{(C_{23}^{+} - 1.2C_{23})}{0.4\gamma_4} \cdot$$

$$\begin{bmatrix} (-0.8\gamma_3 + 2/3\psi\eta - 0.2\gamma_4)^2 \\ +(-0.4\gamma_3 + 1/3\psi\eta + 0.4\gamma_4)^2 \end{bmatrix}^{1/2}$$

$$\gamma_3 = 2.5\left[\frac{(b_{23}-2b_{13})}{\left(\frac{(C_{23}^{+}-1.2C_{23})}{(1.2C_{23}-0.4T_{13}-0.8T_{23})}+1\right)}\cdot\right.$$
$$\left.\left\{\frac{(C_{21}+0.4T_{13}-0.2T_{23})}{(2.5C_{23}^{+}-T_{13}-2T_{23})}-\frac{0.1(C_{23}^{+}-1.2C_{23})}{(1.2C_{23}-0.4T_{13}-0.8T_{23})}-0.1\right\}\right]$$
$$+1.25b_{23}$$

$$\gamma_4 = \frac{\frac{(C_{23}^{+}-1.2C_{23})}{(1.2C_{23}-0.4T_{13}-0.8T_{23})}(b_{23}-2b_{13})}{\left(\frac{(C_{23}^{+}-1.2C_{23})}{(1.2C_{23}-0.4T_{13}-0.8T_{23})}+1\right)}$$

$$\psi\eta = 1.2\left(\frac{(C_{23}^{+}-1.2C_{23})}{(1.2C_{23}-0.4T_{13}-0.8T_{23})}+1\right)\cdot(\gamma_3-\gamma_4)$$
$$-\frac{(C_{23}^{+}-1.2C_{23})3b_{13}}{(1.2C_{23}-0.4T_{13}-0.8T_{23})}$$

Solution of program Equation (8.45)

The Lagrangian of the problem is:

$$\begin{aligned}
&L(a,\hat{t},\delta,\lambda,\Omega) = a(b_{13}\delta_{13}+b_{23}\delta_{23})\\
&+\gamma_1\left(C_{13}-\frac{2}{3}(T_{13}+(\hat{t}+a)\delta_{13})-\frac{1}{3}(T_{23}+(\hat{t}+a)\delta_{23})\right)\\
&+\gamma_2\left(C_{12}-\frac{1}{3}(T_{13}+(\hat{t}+a)\delta_{13})+\frac{1}{3}(T_{23}+(\hat{t}+a)\delta_{23})\right)\\
&-\zeta(\lambda(C_{13}-(T_{13}+\hat{t}\delta_{13}))\\
&+\varepsilon(C_{13}-(T_{13}+\hat{t}\delta_{13}))\\
&+\varphi(1-\delta_{13}^2-\delta_{23}^2)+\kappa a+\pi\lambda
\end{aligned} \tag{8.85}$$

where γ_1 and γ_2 are the Lagrange multipliers associated with transmission capacity on the lines 1-3 and 1-2 in the expanded network, respectively. ζ is the multiplier associated with the Kuhn-Tucker condition of transmission capacity in the pre-expansion network for line 1-3. This line has the Lagrange multiplier λ associated with it before expansion. ε is the investor's marginal value of transmission capacity in the pre-expansion network when allocating incremental FTRs. The normalization condition has the multiplier φ and the non-negativity conditions have the associated multipliers κ and π. The first order conditions are:

$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial a}=(b_{13}\delta_{13}+b_{23}\delta_{23})-(\frac{2}{3}\delta_{13}+\frac{1}{3}\delta_{23})\gamma_1 \tag{8.86}$$
$$-(\frac{1}{3}\delta_{13}-\frac{1}{3}\delta_{23})\gamma_2=0,$$
$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \delta_{13}}=ab_{13}-\frac{2}{3}(\hat{t}+a)\gamma_1-\frac{1}{3}(\hat{t}+a)\gamma_2 \tag{8.87}$$
$$+\zeta\lambda\hat{t}-\varepsilon\hat{t}-2\varphi\delta_{13}=0,$$
$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \delta_{23}}=ab_{23}-\frac{1}{3}(\hat{t}+a)\gamma_1+\frac{1}{3}(\hat{t}+a)\gamma_2 \tag{8.88}$$
$$-2\varphi\delta_{23}=0,$$
$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \hat{t}}=-(\frac{2}{3}\delta_{13}+\frac{1}{3}\delta_{23})\gamma_1-(\frac{1}{3}\delta_{13}-\frac{1}{3}\delta_{23})\gamma_2 \tag{8.89}$$
$$+\delta_{13}\zeta\lambda-\delta_{13}\varepsilon=0,$$
$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \lambda}=-\zeta(C_{13}-T_{13}-\hat{t}\delta_{13})=0, \tag{8.90}$$
$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \gamma_1}=C_{13}-\frac{2}{3}(T_{13}+(\hat{t}+a)\delta_{13}) \tag{8.91}$$
$$-\frac{1}{3}(T_{23}+(\hat{t}+a)\delta_{23})=0,$$
$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \gamma_2}=C_{12}-\frac{1}{3}(T_{13}+(\hat{t}+a)\delta_{13}) \tag{8.92}$$
$$+\frac{1}{3}(T_{23}+(\hat{t}+a)\delta_{23})=0,$$
$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \zeta}=-\lambda(C_{13}-T_{13}-\hat{t}\delta_{13})=0, \tag{8.93}$$
$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \varepsilon}=(C_{13}-T_{13}-\hat{t}\delta_{13})=0, \tag{8.94}$$
$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \varphi}=1-\delta_{13}^2-\delta_{23}^2=0, \tag{8.95}$$
$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \kappa}=a>0,\ \kappa=0, \tag{8.96}$$
$$\frac{\partial L(a,\hat{t},\delta,\lambda,\Omega)}{\partial \pi}=\lambda>0,\ \pi=0, \tag{8.97}$$

The solution for the first order conditions is given by:

$$\delta_{13}=\frac{(1/3\gamma_1-1/3\gamma_2)}{\left((2/3\gamma_1+1/3\gamma_2-\zeta\lambda)^2+(1/3\gamma_1-1/3\gamma_2)^2\right)^{1/2}}$$
$$\delta_{23}=\frac{-(2/3\gamma_1+1/3\gamma_2-\zeta\lambda)}{\left((2/3\gamma_1+1/3\gamma_2-\zeta\lambda)^2+(1/3\gamma_1-1/3\gamma_2)^2\right)^{1/2}}$$

$$a = \frac{C_{12}}{\delta_{13}}$$

$$\hat{t} = \frac{(C_{13} - T_{13})}{\delta_{13}}$$

$$\gamma_1 = \frac{(b_{13} + Bb_{23} + \gamma_2 (B/3 - 1/3))}{(2/3 + B/3)}$$

$$\gamma_2 = \frac{1}{(1 - B - AB + A)} \left[b_{13}(1 + 3A - B - 2A - AB) \right.$$

$$\left. + b_{23}(B + 3AB - B^2 - 2A - A\,B) \right]$$

$$\zeta\lambda = (1 + A)\gamma_1 - A(b_{13} + b_{23})$$

with

$$A = \frac{C_{12}}{(C_{13} - T_{13})}$$

$$B = \frac{1}{(1 + A)} \frac{(C_{13} - 2C_{12} - T_{23})}{(C_{13} - T_{13})}$$

The power transfer distribution factors

This appendix derives the power transfer distribution factors (PTDFs) for the three-node network with two parallel lines, and where all lines have identical reactance. The net injection (or net generation) of power at each bus is denoted P_i. We have the following relationship between the net injection, the power flows P_{ij} and phase angles θ_i:

$$P_i = \sum_j P_{ij} = \sum_j \frac{1}{x_{ij}} (\theta_i - \theta_j)$$

where x_{ij} is the line inductive reactance in per unit.

We can write the power flow equations as:

$$\begin{bmatrix} P_1 \\ P_2 \\ P_3 \end{bmatrix} = \begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix} \begin{bmatrix} \theta_1 \\ \theta_2 \\ \theta_3 \end{bmatrix}$$

The matrix is called the susceptance matrix. The matrix is singular, but by declaring one of the buses to have a phase angle of zero and eliminating its row and column from the matrix, the reactance matrix can be obtained by inversion. The resulting equation then gives the bus angles as a function of the bus injection:

$$\begin{bmatrix} \theta_2 \\ \theta_3 \end{bmatrix} = \begin{bmatrix} 2/3 & 1/3 \\ 1/3 & 2/3 \end{bmatrix} \begin{bmatrix} P_2 \\ P_3 \end{bmatrix}$$

The *PTDF* is the fraction of the amount of a transaction from one node to another node that flows over a given line. $PTDF_{ij,mn}$ is the fraction of a transaction from node *m* to node *n* that flows over a transmission line connecting node *i* and node *j*. The equation for the *PTDF* is:

$$PTDF_{ij,mn} = \frac{x_{im} - x_{jm} - x_{in} + x_{jn}}{x_{ij}}$$

where x_{ij} is the reactance of the transmission line connecting node *i* and node *j* and x_{im} is the entry in the i^{th} row and the m^{th} column of the bus reactance matrix. Utilizing the formula for the specific example network in Figure 8-2 gives:

$PTDF_{12,13} = 1/3$, $PTDF_{13,13} = 2/3$, $PTDF_{23,13} = 1/3$,

$PTDF_{12,23} = -1/3$, $PTDF_{13,23} = 1/3$, $PTDF_{23,23} = 2/3$

$PTDF_{21,13} = -1/3$, $PTDF_{21,23} = 1/3$

9 Provision of financial transmission rights[131]

This chapter studies the risks faced by the providers of financial transmission rights (FTRs). The introduction of FTRs in different systems in the USA must be viewed in relationship to the organization of the market. Often, private players own the central grid, while an independent system operator (ISO) operates the grid. The revenues from transmission congestion collected in the day-ahead and balancing markets should give the ISO sufficient revenues to cover the costs associated with providing FTRs. This can be ensured if the issued FTRs fulfil the simultaneous feasibility test described by Hogan. This test on a three-node network is studied under different assumptions to find the maximum volumes which can be sold, including contingency constraints. Next the feasibility test is analyzed when taking into account the proceeds from the FTR auction, and demonstrates that a higher volume might be issued. We introduce uncertainty under different scenarios for locational prices and calculate the maximum provided volumes. As a tool for risk management, the provider of the FTRs can use the Value at Risk approach. Finally, the provision of FTRs by private parties is discussed.

9.1 Introduction

Transmission rights are needed to hedge long-distance forward trading. If they are well designed, they will minimize forward-trading risks (Stoft, 2002). If no such instruments are available, trading will be inhibited. An optimal schedule may result in loads that are located far from generators and create counterflows between loads and generators that are netted out before the actual schedule. Using financial transmission rights means that transmission costs will net out and every load and generator will pay and be paid as if it had traded locally.

An independent system operator (ISO) can provide financial transmission rights (FTRs) as long as the payments to the FTR holders are less than or equal to the rents the ISO receives from transmission congestion (in the day-ahead and balancing markets). To calculate whether the volume of issued FTRs is feasible, a model network is used that is supposed to represent the actual network. If the network is an inaccurate description or there are unexpected contingencies or outages (of transmission lines or facilities) the ISO can run into financial revenue shortfall risks. On the other hand, a private party does not have to perform this feasibility calculation. As long as it can cover its expenses in the long-run, it can undertake the risk of overselling FTRs.

An element that is not taken into account in the feasibility calculation by the ISO is the proceeds from the FTR auction, which add to the congestion rent. Higher proceeds from the FTR auction will allow the provider to sell higher volumes. If the party is a generator it may have the ability to sell the largest volume of FTRs, since it can affect the generation output and thereby the local spot prices. In most FTR markets, the proceeds from the FTR auctions are distributed to the transmission owners. However, we propose that it is possible to use the proceeds to fund the payments to FTR holders, including merchant transmission investors. In this case, we need a separate revenue stream as for example a tax on energy to pay for the capital of the

[131] I am grateful for comments from Professor Ross Baldick.

transmission system. Likewise, a transmission investor might want the proceeds from the auction to pay off the capital.

9.2 Financial transmission rights

An FTR (Hogan, 1992 and 2003) entitles its owner to be paid the price difference between two locations (buses) times the contract quantity over a specified time period. This payment will net out any price risk associated with using that path (i.e. paying congestion fees) if the contract quantity matches the quantity traded. Such payments will be made to the owner of the right regardless of the owner's actual usage of the transmission system. The payments under this right are therefore independent of the owner's physical use of the grid. Even if the congestion risk is hedged, traders will still be exposed to locational price signals and should still be able to make efficient choices for production and consumption. The mathematical formulation for the payoff for the FTR is:

$$\text{FTR} = (P_j - P_i)\, Q_{ij} \tag{9.1}$$

where P_j is the bus price at location j, P_i is the bus price at location i and Q_{ij} is the directed quantity specified in the FTR from point i to point j. The payoff of the FTR is only dependent on the bus prices, not on the power flow, and it may be positive, zero or negative. An FTR may be acquired by purchasing it in auctions, secondary markets or by investing in transmission lines. Typically, an ISO would provide FTRs through an auction held periodically, or by an initial allocation. After the initial allocation, the FTRs could be traded through secondary markets.

Locational prices are required before an FTR can be defined. These depend on congestion and may depend on losses. FTRs are typically forward contracts that are settled in the day-ahead market. The locational prices that they are settled against will change during the specified contract period, so the value of the total payment is calculated by averaging a series of fluctuating locational bus prices.

FTRs can be designated as one-way options in which case the holder is not responsible for negative payments. The mathematical formulation is:

$$\text{FTR\_option} = \max\left((P_j - P_i)\, Q_{ij}, 0\right) \tag{9.2}$$

Payments from an option are non-negative, and the option will have a clearing price greater than or equal to the price of an FTR obligation.

If the objective is to fully and efficiently utilize the network, schedules that create counterflows are necessary because they relieve congestion. In the presence of counterflows, options issued by the ISO will not allow full hedging. For a more thorough introduction to the FTR concept we refer to Hogan (1992 and 2003).

9.3 The simultaneous feasibility test

In general, the ISO can issue more obligations than options if all FTRs are defined as options. The reason is that obligations will allow the ISO to assume that counterflows will either be provided by the FTR holders or the holders will pay the ISO for the negative value of the right. By using options the ISO cannot assume that counterflows will be provided, nor will it receive any payments from the rights holder.

For these reasons, parties should be willing to pay more for options than obligations. Ideally, both options and obligations could be provided by the ISO and the market could sort out the mix of rights it found to be most useful, given the market transactions each party wished to pursue.

An important consideration in defining FTRs is that they fulfill the feasibility condition. If this is the case, revenue sufficiency is ensured and the congestion rent is sufficient to cover the payments to the FTR holders. The feasible set of FTRs is any set of FTRs that corresponds to a feasible power flow. A feasible power flow is one that does not violate the power transmission limit of any line.[132] Other sets are infeasible (Stoft, 2002). The set of FTRs to be issued is often restricted to be any feasible set. Restricting FTRs by restricting the sum of the corresponding power flows automatically accounts for counterflows, so trade will not be restricted except because of physical limitations. If a full set of FTRs is to be issued, then traders are allowed to purchase any feasible set of FTRs (Stoft, 2002).

Traders often prefer FTRs that cannot have negative values, such as options. Options make revenue sufficiency more difficult to guarantee without severely restricting the sale of FTRs. The set of financial options that ensures revenue sufficiency must therefore be smaller than the feasible set of FTR obligations.

Hogan and Pope (2001) demonstrate that for FTR obligations, options or a combination of both, the simultaneous feasibility test (SFT) ensures that the implied power flows $K(y)$ from the contracts satisfy all system constraints (in the example below, the transmission capacity limits):

$$K(y) \le C \tag{9.3}$$

where y is the vector of net loads on the system and C is the vector of transmission line capacities. In a DC load flow approximation $K(y)$ can be linearized to $K(y) \approx K(y^*) + \nabla K(y^*)(y - y^*)$ where y^* is an operating point and $\nabla K(y^*)$ equals the matrix of shift factors[133] H. The matrix H includes negative contributions due to counterflows. It is assumed that $y^* = 0$ and $K(y^*) = Hy^* = 0$ resulting in $K(y) \approx Hy$. Furthermore, $\{Q^f_{mn}\}$ is the set of FTR obligations and $\{Q^o_{mn}\}$ is the set of FTR options. For options only positive congestion payments are made by the system operator. The SFT in the case of obligations is satisfied if and only if:

$$\sum_{mn}^{F} H_{ijmn} Q^f_{mn} \le C_{ij} \quad 1 \le i, j \le N \tag{9.4}$$

where the summation is across all obligations (F) issued between the buses in the network that contribute with a flow over the specified transmission line ij. H_{ijmn} is the fraction of a transaction from bus m to bus n that flows over a transmission line connecting bus i and bus j. The maximum volume (Q^o) of possible issued options in the case of a DC load flow approximation is determined by:

[132] A lossless transmission network is assumed.
[133] Also called power transfer distribution factors (PTDFs).

$$\sum_{mn}^{O} \max(0, H_{ijmn} Q_{mn}^{o}) \le C_{ij} \quad 1 \le i, j \le N \tag{9.5}$$

where the summation is across all options (O) issued between the buses in the network that contribute with a flow over the specified transmission line *ij*. The interpretation of the above equation is that counterflows from options must be ignored (i.e. negative shift factors) and only options with the same direction along the constraint are considered.

A combination of FTR obligations and options satisfies the SFT when:

$$\sum_{mn}^{F} H_{ijmn} Q_{mn}^{f} + \sum_{mn}^{O} \max(0, H_{ijmn} Q_{mn}^{o}) \le C_{ij} \quad 1 \le i, j \le N \tag{9.6}$$

ensuring sufficient payments to the system operator. The SFT is guaranteed by the convexity of the solution set.

To carry out an SFT in a network we run an optimal power flow model without economic dispatch and check that no limits are violated. An FTR obligation[134] between two locations is described as a vector:

$$FTR_{mn} = Q_{mn}^{f}(0, ..., -1_{m}, ..., 1_{n}, ..., 0)^{T} \tag{9.7}$$

where Q_{mn}^{f} is the amount of energy specified in the FTR. An FTR is then viewed as an injection (source) Q_{mn}^{f} of electricity at bus *i* and a withdrawal (sink) of Q_{mn}^{f} at bus *j*.

FTRs between different buses in a three-bus network can be allocated according to the generic transaction scheme shown in Table 9-1.

Table 9-1. Generic transaction scheme describing FTRs.

Bus	Injection/source	Withdrawal/sink
1	$-(Q_{12}^{f} + Q_{13}^{f})$	$(Q_{21}^{f} + Q_{31}^{f})$
2	$-(Q_{21}^{f} + Q_{23}^{f})$	$(Q_{12}^{f} + Q_{32}^{f})$
3	$-(Q_{31}^{f} + Q_{32}^{f})$	$(Q_{13}^{f} + Q_{23}^{f})$
Total sink equals total source	$\pm(Q_{12}^{f} + Q_{13}^{f} + Q_{23}^{f} + Q_{21}^{f} + Q_{31}^{f} + Q_{32}^{f})$	

To illustrate, an FTR of 10 units is assumed between buses 1-2. This FTR would have an injection component of 10 at bus 1 and a withdrawal component of 10 at bus 2. Another FTR of 15 units between buses 1-3 would similarly have 15 units of injection and withdrawal. The total amount of injection would then be 25 units of injection at bus 1, 10 units of withdrawal at bus 2, and 15 units of withdrawal at bus 3.

[134] No losses are assumed.

The total amount of injected power is 25 units equal to the total amount withdrawn, 25 units. The amount of issued FTRs is feasible if no power flow limits are violated.

9.4 Optimal power flow model

We base our analysis on a lossless and linear DC-equivalent model with all interface-reactances equal to 1 as described in Bjørndal and Jørnsten (2001). The model ignores losses. The mathematical formulation is:

N: the number of buses,
K: the number of transmission lines,
C_{ij}: the capacity of the transmission line from i to j,
L_l: the set of directed arcs in a path going through the independent loop l representing Kirchhoff's loop rule,
q_i^d : the quantity of real power consumed at bus i,
q_i^s : the quantity of real power generated at bus i,
y_i : the net load at bus i,
$p_i^d(q_i^d)$: the demand function of bus i,
$p_i^s(q_i^s)$: the supply function of bus i,
q_{ij} : the power flow over the line from bus i to bus j,
P_{Zm} : the price in zone Z_m.

Then the objective becomes:

$$\max \sum_{i=1}^{N}\left(\int_0^{q_i^d} p_i^d(q)dq - \int_0^{q_i^s} p_i^s(q)dq\right) \tag{9.8}$$

s.t.

$$y_i = -(q_i^s - q_i^d) = -\sum_{j\neq i} q_{ij} \qquad i=1,\dots,N-1 \tag{9.9}$$

$$\sum_{ij\in L_l} q_{ij} = 0 \qquad l=1,\dots,K-N+1 \tag{9.10}$$

$$\sum_{i=1}^{N}(q_i^s - q_i^d) = 0 \tag{9.11}$$

$$q_{ij} \le C_{ij} \qquad 1\le i, \quad j\le N \tag{9.12}$$

$$\begin{aligned} p_i^s(q_i^s) &= P_{Z_m} \qquad i\in Z_m, \quad m=1,\dots,N \\ p_i^d(q_i^d) &= P_{Z_m} \end{aligned} \tag{9.13}$$

The objective function in the model, Equation (9.8), is the total social welfare which in turn equals the sum of consumer surplus and generator surplus. Equation (9.9) represents Kirchhoff's junction rules constituting N-1 independent equations. Equation (9.10) represents Kirchhoff's loop rules with $L=(L_1,\dots,L_{K-N+1})$ being the set of independent loops, and L_l being the set of directed arcs in a path going through loop l. Equation (9.11) describes the energy conservation. Equation (9.12) describes the transmission capacity limits. Equation (9.13) calculates the bus prices. Alternatively, they can be found as the shadow prices of the Kirchhoff's junction rules. In every bus (node) there are production and consumption facilities.

The real power flows from the buses will depend on the net supply at the respective buses. The decision variables in the model are the quantities produced and consumed and the bus prices. The variables are coupled through the supply and demand functions. The model can be used to perform the SFT. In this case supply and demand are fixed and the model calculates the associated power flows. The network considered is shown in Figure 9-1.

The demand and cost functions are assumed to be quadratic, implying linear demand and supply. Demand in bus i is given $p_i = a_i - b_i q_i$ where p is the price at the actual bus and a and b are positive constants. Supply is given by $p_i = c_i q_i$ where c is a positive constant. We assume identical demand functions at every bus, and varying cost functions as shown in Table 9-2.

Table 9-2. Parameters for the supply and demand functions.

Bus	Consumption		Supply
	a_i	b_i	c_i
1	20	0.05	0.1
2	20	0.05	0.2
3	20	0.05	0.3

Figure 9-1 and Figure 9-2 show the uncongested case and the congested case respectively. Maximum transmission capacity over interface 1-2 is 15. The other interfaces have transmission limits equal to 100. Because every interface consists of two lines, the capacity of each line is half of the total capacity. The reactance of each line equals 2, resulting in total interface reactance of 1 (two parallel lines).

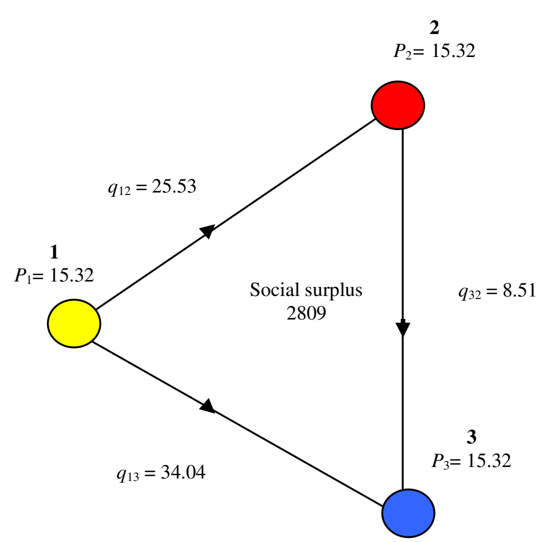

Figure 9-1. Economic dispatch in an uncongested three-bus network.

Security constraints take into account the post-contingency flows that arise due to loss of lines or generators. The usual model is to use the n-1 criterion where the outage of one transmission line or one generator is considered.[135]

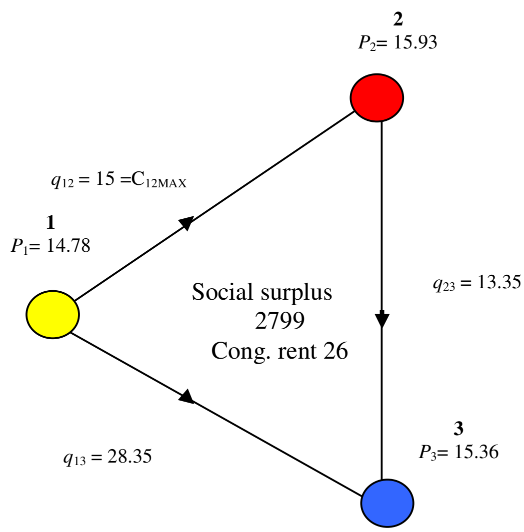

Figure 9-2. Economic dispatch when transmission congestion is present in a three-bus network.

9.5 Numerical examples

In the presence of losses and congestion, the net rents collected under a locational pricing model would be greater than the net payments to participants. This net revenue is referred to as the congestion rent. It is the difference between the sum of withdrawals (q_i^d) and injections (q_i^s) times the bus prices (P_i). The congestion rent (R_C) can be stated mathematically for the three-bus network with no losses as:

$$R_C = \sum_{i=1}^{3} q_i^d P_i - \sum_{i=1}^{3} q_i^s P_i = q_{12}(P_2 - P_1) + q_{13}(P_3 - P_1) + q_{23}(P_3 - P_2) = 26 \qquad (9.14)$$

where q_{ij} is the power flow from bus i to bus j. The second equality would not hold if there were losses.

9.5.1 Financial transmission right obligations

The expected value of an FTR between buses i and j is given by the expected future congestion price between the buses. The maximum provided volume of one FTR is then found by assuming that the payment to the FTR holder equals the congestion rent:

[135]Including simultaneous outage of several lines and/or generators would increase the computational burden.

$$Q_{ij}^{f} = \frac{R_C}{(P_j - P_i)} \tag{9.15}$$

Alternatively, we can formulate the maximum volume of FTR obligations between buses *i-j* connected by a congested line *k* in a three-bus network with identical reactance as:

$$Q_{ij}^{f} = \frac{3}{2}\min_{l}\left\{C_k, 2C_l\right\} \tag{9.16}$$

where C_k is the maximum transmission capacity of the line between buses *i-j*, and C_l is the maximum transmission capacity of each of the other lines in the network connecting buses *i* and *j* indirectly. The rule is determined by the impedance that is twice as high for the path 1-3-2 compared to path 1-2. Therefore 2/3 of the power takes the direct path from bus *i* to *j* and 1/3 the longer path. Generally, the shift factors can be found from the matrix of shift factors as illustrated in Figure 9-3 (see the appendix for how to calculate the shift factor matrix elements). FTR obligations between the buses *i* and *j* and the remaining bus (called an FTR obligation between buses *m-n*) will have a maximum issued volume equal to:

$$Q_{mn}^{f} = 3\min_{l}\left\{C_k, \frac{1}{2}C_l\right\} \tag{9.17}$$

due to the shift factor 1/3. The simultaneous provision of several FTRs modifies this rule so that the congestion rent must be shared among several FTRs. The magnitude of the congestion rent and the implied FTR power flows determines the maximum volume of provided FTRs.

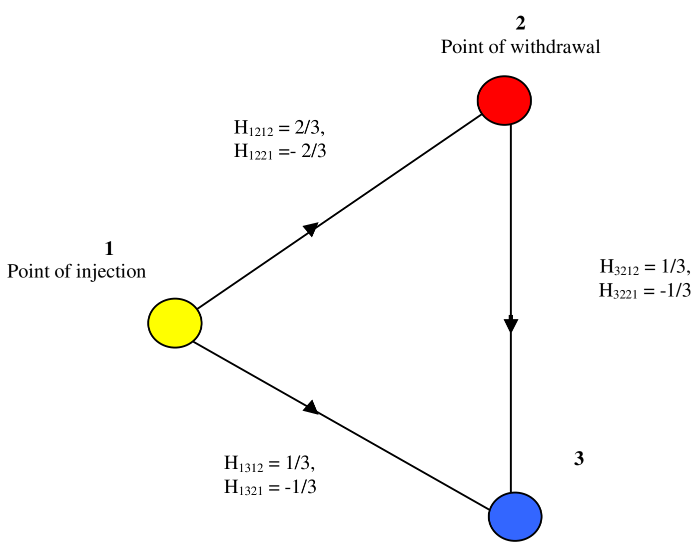

Figure 9-3. Some elements in the shift factor matrix.

We calculate the maximum volume of FTRs between different buses. First, we consider when the ISO issues FTRs between buses 1-2 in the network as shown in Figure 9-2. The maximum volume of FTR is calculated as:

$$Q_{12}^f = \frac{R_C}{(P_2 - P_1)} = \frac{3}{2} C_{12} = 22.5 \tag{9.18}$$

A smaller volume gives the ISO an excess revenue which could be redistributed according to a specified rule. However, if the ISO provides the same volume plus 22.5 (total volume 45) in the opposite direction (from 2 to 1), the net directed power flow from 2 to 1 is 15 because the power flows cancel. In this situation, the ISO can issue any volume *Q* plus 22.5 as long as there is an equal volume *Q* in the opposite direction.

Similarly, the maximum volume of FTRs between buses 1-3 can be calculated as:

$$Q_{13}^f = \frac{R_C}{(P_3 - P_1)} = 3C_{12} = 45. \tag{9.19}$$

Another possibility is a simultaneous issue of FTRs between buses 1-2 and 1-3. The maximum volumes of FTRs are described as:

$$Q_{12}^f (P_2 - P_1) + Q_{13}^f (P_3 - P_1) = R_C \tag{9.20}$$

After rearranging the volume of FTRs between 1 and 2 this gives:

$$Q_{12}^f = \frac{R_C}{(P_2 - P_1)} - \frac{Q_{13}^f (P_3 - P_1)}{(P_2 - P_1)} = 22.5 - 0.5 Q_{13}^f \tag{9.21}$$

The feasible space of FTRs is illustrated in Figure 9-4**.**

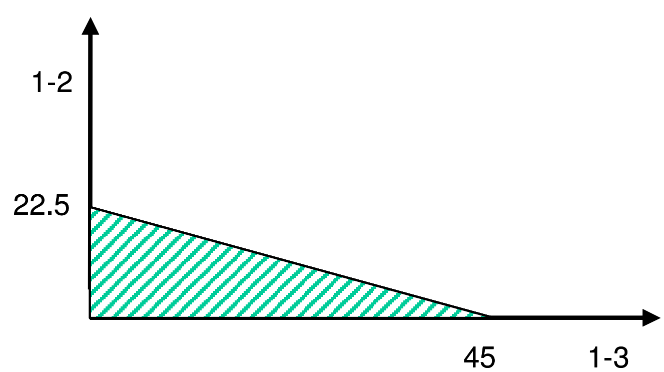

Figure 9-4. The feasible space of FTRs 1-2 and 1-3.

Similarly, the maximum volumes of FTRs between buses 1-2 and buses 3-2 are:

$$Q_{12}^f = \frac{R_C}{(P_2 - P_1)} - \frac{Q_{32}^f (P_2 - P_3)}{(P_2 - P_1)} = 22.5 - 0.5 Q_{32}^f \tag{9.22}$$

and between buses 1-2 and buses 2-3:

$$Q_{12}^f = \frac{R_C}{(P_2 - P_1)} - \frac{Q_{23}^f (P_3 - P_2)}{(P_2 - P_1)} = 22.5 + 0.5 Q_{23}^f . \tag{9.23}$$

The formula shows that increasing the volume of FTRs between buses 2-3 also increases the volume of FTRs between buses 1-2, due to counterflows. The feasible space of FTRs is illustrated in Figure 9-5.

Figure 9-5. The feasible space of FTRs 1-2 and 2-3.

9.5.2 Contingency constraints

Contingency constraints limit the volume of issued FTRs. For example if we assume an outage of one line at the 1-2 interface, the remaining capacity will be 7.5 units. The line reactance for line 1-2 is 2, due to the outage. The shift factor matrix elements change because of the new network topology. Examples are $H_{1212} = 1/2$ and $H_{1213} = 1/4$.

The congestion rent from the economic dispatch in this case will be 25.6, which is slightly lower than when the line is in service (26 units). The corresponding economic dispatch is shown in Figure 9-6.

The constraint reduces the volume of FTR between buses 1-2 so that the ISO can issue to 15.0 or 33%. Similarly the maximum volumes of 1-2 and 1-3 FTRs utilizing the *n*-1 criterion are described as:

$$Q_{12}^f = \frac{R_C}{(P_2 - P_1)} - \frac{Q_{13}^f (P_3 - P_1)}{(P_2 - P_1)} = 15 - 0.5 Q_{13}^f \tag{9.24}$$

which is more restrictive than without contingency.

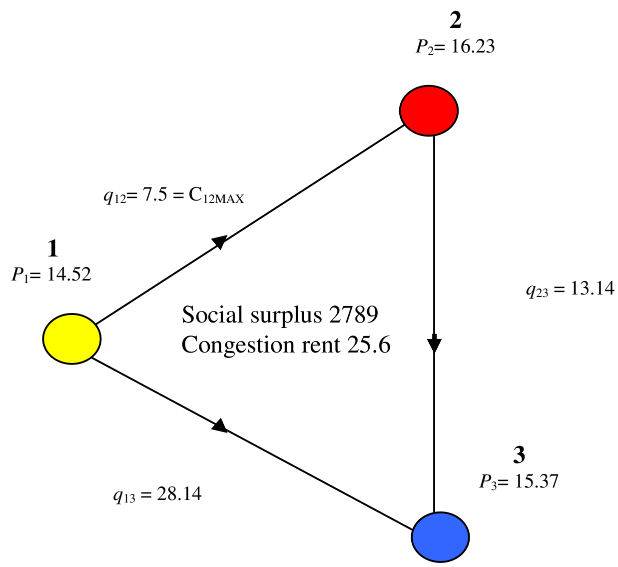

Figure 9-6. Economic dispatch when transmission congestion and one contingency are present in a three-bus network.

Transpower New Zealand has excluded transmission lines with outages longer than 2 days in a 30-day period in its network describing the SFT (Transpower, 2001). The outage of the remaining lines describing the network is equivalent to 7% of the duration of the FTRs. In our network example, a conservative criterion is that the outage of the 1-2 line is present only as long as the duration of the FTRs and hence the issued volume is 11.25. Usually outages are present for shorter times, and an optimistic upper bound is therefore 22.5 units. However, in optimal power flow models, the practice is to include security constraints and run a security-constrained economic dispatch.

9.5.3 Financial transmission right options

Provision of options will be more restrictive because they do not provide counterflows. Consider the case when the ISO issues options between buses 1-2 then the maximum volume, 22.5 units, will be the same as for obligations. If the ISO issues options in opposite directions between the same buses the maximum volume in each direction is still 22.5 units compared with obligations where a higher volume could be issued. The reason is that options do not provide counterflows and any possible exercise of options must be taken into account. In the above example, only one option is exercised at a time with an associated maximum volume of 22.5.

Utilizing that options do not result in counterflows in the specific three-bus transmission network we get a relationship between 1-2 and 1-3 FTR options:[136]

$$\frac{2}{3}Q_{12}^{o} + \frac{1}{3}Q_{13}^{o} \leq 15 \tag{9.25}$$

[136] The constraints on lines 1-3 and 2-3 are ignored since they are not binding.

and solving for Q_{12}^{o} gives the maximum volume of options between buses 1-2:

$$Q_{12}^{o} = 22.5 - 0.5Q_{13}^{o}, \quad Q_{13}^{o} \le 45 \tag{9.26}$$

Another possibility is to have options between buses 1-2 and 2-3. The relevant constraints are:

$$\frac{2}{3}Q_{12}^{o} \le 15 \text{ and } \frac{1}{3}Q_{23}^{o} \le 15 \tag{9.27}$$

since the options do not create any counterflows. The maximum volume for each option is:

$$Q_{12}^{o} = 22.5 \text{ and } Q_{23}^{o} = 45 \tag{9.28}$$

which is lower than in the case of obligations. Combinations of obligations and options are also possible. For example, an obligation between buses 1-2 and an option between buses 2-3 is represented by the constraints:

$$\begin{aligned} &\frac{2}{3}Q_{12}^{f} \le 15 \\ &\frac{1}{3}Q_{23}^{0} - \frac{2}{3}Q_{12}^{f} \le 15. \end{aligned} \tag{9.29}$$

The maximum volume of provided 1-2 obligations is the same as before: 22.5 units. The maximum volume of 2-3 options is:

$$Q_{23}^{0} = 45 + 2Q_{12\max}^{f} = 45 + 2 \cdot 22.5 = 90 \tag{9.30}$$

which is also lower than in the case with only obligations. The 2-3 option would have zero payoff in the economic dispatch example in Figure 9-2 because the price difference between buses 3 and 2 is negative. When we take the security constraints into account, we get the maximum volume for a single obligation or option as specified in Table 9-3. Similarly, we can specify some maximum volume combinations of options and obligations in Table 9-4. The results demonstrate that the volume of issued options is more restrictive for some of the lines because they do not create counterflows.

Table 9-3. The maximum volume of provided FTR obligations or options when only one FTR is issued.

buses	FTR obligation	FTR option	(*n*-1) criterion
1-2	22.5	22.5	15
1-3	45	45	30
2-3	45	45	30
3-2	45	45	30

Table 9-4. The maximum volume of provided FTRs when several FTRs are issued simultaneously.

buses	FTR obligation	FTR option	(n-1) criterion
1-2 and 2-1 obligation	Any volume Q plus 22.5 in one direction as long as there is an equal volume Q in the opposite direction	22.5 in both directions	Any volume Q plus 15 in one direction as long as there is an equal volume Q in the opposite direction for obligations, 15.0 in both directions for options
1-2 and 1-3 obligation	$Q_{12}^{f} = 22.5 - 0.5Q_{13}^{f}$ $Q_{13}^{f} \le 45$	$Q_{12}^{o} = 22.5 - 0.5Q_{13}^{o}$ $Q_{13}^{o} \le 45$	$Q_{12}^{f/o} = 15 - 0.5Q_{13}^{f/o}$ $Q_{13}^{f/o} \le 30$
1-2 and 3-2 obligation	$Q_{12}^{f} = 22.5 - 0.5Q_{32}^{f}$ $Q_{32}^{f} \le 45$	$Q_{12}^{o} = 22.5 - 0.5Q_{32}^{o}$ $Q_{32}^{o} \le 45$	$Q_{12}^{f/o} = 15 - 0.5Q_{32}^{f/o}$ $Q_{32}^{f/o} \le 30$
1-2 and 2-3 obligation	$Q_{12}^{f} = 22.5 + 0.5Q_{23}^{f}$ $Q_{23}^{f} \le 200$	$Q_{12}^{o} = 22.5$ and $Q_{23}^{o} = 45$	$Q_{12}^{f} = 15 + 0.5Q_{23}^{f}$ $Q_{23}^{f} \le 185$ $Q_{12}^{o} = 15$ and $Q_{32}^{o} = 30$
1-2 obligation and 2-3 option	$Q_{12}^{f} = 22.5$ and $Q_{23}^{o} = 90$		$Q_{12}^{f} = 15$ and $Q_{23}^{o} = 60$

9.6 Expanding the feasible space of financial transmission rights

Until now we have not taken the proceeds from the FTR auction into account when calculating the maximum volume issued. When they are considered, the formulas for maximum volume must be modified since there will be additional revenue from the FTR sales. The payments to the FTR holders must be less than or equal to the congestion rent and the proceeds from the FTR auction. We assume that the proceeds from the FTR auctions are related to the period when the FTRs are settled. This holds true for the auctions in the PJM market in the US. The general relationship between the payoff, the price and the maximum volume of a single FTR is described as:

$$Q_{ij}^{f}(P_j - P_i - p_{ij}) = R_C \tag{9.31}$$

where p is the price of the FTR. R_C is calculated from the bus prices and their associated net loads in the optimal power flow model. We first assume that the FTR prices are independent of the FTR volume issued. Consider the case when $(P_j - P_i - p_{ij}) > 0$. This occurs when the FTR prices are less than the price differential (i.e. the FTRs are under-priced). The greater $(P_j - P_i - p_{ij})$ is, the smaller the maximum volume of FTRs, assuming everything else is equal. We understand that the relatively under-priced FTRs (the FTR price is small compared to the price differential) cause the ISO to issue a smaller volume because it is responsible for payments (i.e. price differentials) to FTR holders that are greater than the price for which they are sold. The reverse is true if $(P_j - P_i - p_{ij}) < 0$ the selling price is greater than the price differential (i.e. the FTRs are over-priced). The volume provided is then negative, meaning that the ISO profits on the provision of the FTRs. When the selling price equals the price differential, the maximum volume sold is undefined. The formula demonstrates that by taking into account the selling price it is possible to issue a higher FTR volume. This is demonstrated for obligations between buses 1-2 and a selling price equal to the half of the price differential as:

$$Q_{12}^{f} = \frac{R_C}{(P_2 - P_1 - p_{12})} = \frac{26}{(1.15 - 0.5 \cdot 1.15)} \approx 45 \tag{9.32}$$

This is an increase in volume of 100% from 22.5 units. Similarly, the maximum volumes of FTRs between buses 1-2 and 1-3 are described by:

$$Q_{12}^{f}(P_2 - P_1 - p_{12}) + Q_{13}^{f}(P_3 - P_1 - p_{13}) = R_C \tag{9.33}$$

where Q^f is the volume of FTRs. After rearranging the volume of FTRs 1-2 as a function of FTRs between 1 and 3, and assuming that the selling price is equal to the half of the price differential between buses 1-2 this is:

$$Q_{12}^{f} = \frac{R_C}{(P_2 - P_1 - p_{12})} - \frac{Q_{13}^{f}(P_3 - P_1 - p_{13})}{(P_2 - P_1 - p_{12})} = 45 - 0.5 Q_{13}^{f}. \tag{9.34}$$

The expansion of the feasible space of FTRs is illustrated in Figure 9-7. These examples show that a higher volume of FTRs can be issued by taking into account the selling price.

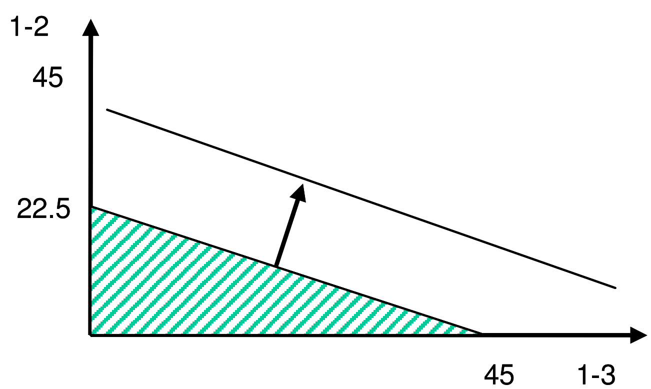

Figure 9-7. The feasible space of FTRs 1-2 and 1-3 taking into account the proceeds from the FTR auction.

Next, we assume that the FTR price is linearly dependent on the volume issued:

$$p_{ij} = a - bQ_{ij}^{f} \tag{9.35}$$

where *a* and *b* are parameters that characterize the demand of FTRs. Substituting for the FTR price and solving for Q_{ij}^{f} gives:

$$Q_{ij}^f = \frac{-(P_j - P_i - a) \pm \sqrt{(P_j - P_i - a)^2 + 4bR_C}}{2b} \tag{9.36}$$

Consider the special case $P_j - P_i = a$. The maximum willingness to pay equals the price differential. Then $Q_{ij}^f = \sqrt{R_C / b}$ and may be more restrictive (depending on *b*) than when the price p_{ij} was considered to be independent of the volume issued. The exact condition when this holds true, is found by comparing the calculated volume with the price independent of volume (e.g. Equation (9.31)):

$$\sqrt{\frac{R_C}{b}} \geq R_C /(a - p_{ij}) \Rightarrow b \leq \frac{(a - p_{ij})^2}{R_C}. \tag{9.37}$$

The key issue of the revenue adequacy test is to ensure that the implied power flows from an FTR do not exceed the transmission capacities. Due to the equivalence between this test and the formula for the feasible volume provided, it might be possible to modify the feasible FTR volume formulation for obligations:

$$\sum_{mn}^{F} (H_{ijmn} - \frac{p_{mn} C_{ij}}{R_C}) Q_{mn}^f \leq C_{ij},\ 1 \leq i, j \leq N \tag{9.38}$$

where p_{mn} is the price of an FTR from bus *m* to bus *n*. To use this feasibility test in practice we first run the optimal power flow model to calculate R_C for the network considered and then use the value found in the above formula.

9.7 Uncertainty

Until now, we have calculated the consequences of the FTR provision under deterministic conditions. Now we will introduce uncertainty by using the scenarios in Table 9-5, where we have calculated the expected bus price and the associated volatility. Bus 3 experiences the highest expected value and volatility. [137]

Table 9-5. The expected bus prices in three different scenarios.

Scenarios/ Probability	Bus 1	Bus 2	Bus 3
No congestion (NC) 50%	15.32	15.32	15.32
Congestion line 1-2 (C12) 30%	14.78	15.93	15.36
Congestion line 1-3 (C13) 20%	14.33	15.41	16.49
Expected price	14.96	15.52	15.57
Volatility	0.39	0.27	0.46

[137] A measure of the uncertainty of the return on asset.

Table 9-6. The maximum volume of FTRs when only one FTR is issued under three different scenarios.

Scenarios/ probability	FTR 1-2	FTR 1-3	FTR 2-3	FTR 3-2
NC 50%	22.5	45	45	45
C12 30%	22.5	45	45	45
C13 20%	45	22.5	45	45
Expected volume	27	40.5	45	45

Table 9-6 shows the maximum volume of provided FTRs when only one FTR is issued under three different scenarios. The highest volume is issued between buses 2-3 (because of a lower price differential) and the lowest volume between buses 1-2 (a higher price differential).

An FTR provider facing uncertainty may use tools to measure the associated risks. One tool is the Value at Risk (VaR) approach. VaR is an attempt to provide a single number for management summarizing the total risk in a portfolio of assets (Hull, 2003). The objective of the approach is to give a financial measure of the statement: "We are *X%* certain that we will not lose more than *V* dollars in the next *N* days." The variable *V* is the VaR of the portfolio. It is usual to assume a confidence interval of 95%, and a time horizon of up to one week. The changes in the asset prices are assumed to have a multivariate distribution[138] and a mean of zero (at least approximately). Mathematically a linear model for the change in the daily value, ΔP, of a portfolio of *N* assets with an amount (or fraction) x_i invested in asset *i* and with a daily return of Δr_i is formulated as:

$$\Delta P = \sum_{i=1}^{N} x_i \Delta r_i \tag{9.39}$$

Only the mean and standard deviation of ΔP is necessary to calculate the VaR. To calculate the standard deviation of ΔP, we define σ_i as the daily volatility of the *i*th asset and ρ_{ij} as the correlation coefficient between the returns on the asset *i* and *j*. The standard deviation is given by:

$$\sigma_P^2 = \sum_{i=1}^{N} \sum_{j=1}^{N} \rho_{ij} x_i x_j \sigma_i \sigma_j \tag{9.40}$$

The standard deviation of the change over *N* days is $\sigma_P \sqrt{N}$ and the 95% VaR for an *N*-day time horizon is $1.65 \cdot \sigma_P \sqrt{N}$.

[138]To facilitate calculations it is assumed normal distributions. A new measure is conditional value at risk (CVaR) which is based on expectation of loss rather than the probability of it, and which does not require that the distribution is symmetric.

Table 9-7. Payments per unit to the FTR holders and total congestion rent under the different scenarios.

FTR per unit payment	FTR 1-2	FTR 1-3	FTR 2-3	Congestion rent
NC 50%	0	0	0	0
C12 30%	1.15	0.58	-0.57	26
C13 20%	1.08	2.16	1.08	48.7
Expected payment	0.56	0.61	0.04	17.5
Volatility	0.56	0.82	0.57	19.2

Table 9-7 shows the payments per unit to the FTR holders and the total congestion rent under the different scenarios. FTRs between buses 1-3 are particular volatile. The congestion rent is highly volatile and with an expected revenue of 17.5 to the ISO. In Table 9-8 we calculated the payments of the FTR provider to FTR holders and VaR (excluding the congestion rent) under the provision of FTRs of 22.5 units between each of the buses (one at a time) 1-2, 1-3, and 2-3. The provider has the greatest risk exposure when it issues FTRs between buses 1-3 because the expected payments are highest in this case. The lowest payments are for FTRs between 2-3 due to counterflows that create a revenue to the provider in scenario C13.

Table 9-8. The payments of the FTR provider and VaR under the provision of 22.5 units FTRs between each of the buses 1-2, 1-3 and 2-3.

FTR	Payments	Volatility of payments	VaR
1-2	12.6	0.56	11.67
1-3	13.7	0.82	18.49
2-3	0.9	0.57	0.85

Table 9-9 shows the expected price differential correlation matrix with congestion under the different scenarios. The price differentials 1-2/2-3 exhibit low correlation (almost zero), while the price differentials 1-2/1-3 and 1-3/2-3 have a higher correlation.

Table 9-9. Expected price differential correlation matrix with congestion under different scenarios.

Correlation matrix	1-2	1-3	2-3
1-2	1.00	0.71	0.04
1-3	0.71	1.00	0.73
2-3	0.04	0.73	1.00

Table 9-10. VaR estimate of payments at 95% confidence level under different scenarios.

Condition	VaR
Congestion with 1-2 (11.25 units)	5.83
Congestion with 1-3 (11.25 units)	9.25
Congestion with 2-3 (11.25 units)	0.43
Congestion with 1-2 (11.25 units) and 1-3 FTRs (22.5 units)	23.05
Congestion with 1-2 (11.25 units) and 2-3 FTRs (22.5 units)	5.93
Congestion with 1-2 (45 units) and 2-3 FTRs (45 units)	23.62

Table 9-10 shows the VaR estimate of payments at 95% confidence level under different provision scenarios without taking into account the auction proceeds. When a single FTR is issued the VaR is highest for 1-3 FTRs and lowest for 2-3 FTRs. The results demonstrate that the greater potential losses are realized when 1-2 and 1-3 FTRs are issued (compared to identical volumes of 1-2 and 2-3 FTRs) because the payments of the provider to FTR holders are relatively high. Conversely, an identical combination of FTRs between buses 1-2 and 2-3 has a much lower VaR and it is possible to issue a higher volume at the same VaR.

Table 9-11 and Table 9-12 show similar results when the auction proceeds are taken into account and assuming that FTR selling prices equal to the half of the price differential. However, because the payments are lower due to the auction proceeds from the FTRs, the VaR will be lower and so will the risk position of the provider. If the selling price is equal to the expected price differential the VaR will be zero. Its risk will completely offset by the revenue from selling FTRs.

Table 9-11. The net positions of the provider under the provision of 22.5 units FTRs between each of the buses 1-2, 1-3 and 2-3, assuming selling prices equal to the half of the price differential.

FTR	Auction proceeds	Payments	Position	Volatility of payments	VaR
1-2	6.3	12.6	6.3	0.56	5.84
1-3	6.85	13.7	6.85	0.82	9.25
2-3	0.45	0.9	0.45	0.57	0.43

Table 9-12. VaR estimate of payments at 95% confidence level, assuming selling prices equal to the half of the price differential.

Condition	VaR
Congestion with 1-2 (11.25 units)	2.92
Congestion with 1-3 (11.25 units)	4.62
Congestion with 2-3 (11.25 units)	0.21
Congestion with 1-2 (11.25 units) and 1-3 FTRs (22.5 units)	11.51
Congestion with 1-2 (11.25 units) and 2-3 FTRs (22.5 units)	2.96
Congestion with 1-2 (45 units) and 2-3 FTRs (45 units)	11.74

9.8 Providers of financial transmission rights

When a private party provides FTRs, it does not have to fulfill the SFT. If the private party can buy insurance in the market, it can over-sell FTRs compared to the ISO that issues FTRs satisfying the SFT. It may also charge a higher price if it is the only one providing FTRs. But, the private party does not receive any rents from transmission congestion (i.e. congestion rents), so in the long-run it must at least price its FTRs to cover the payments to the rights holders.

Third parties may be able to run the market for hedging instruments at lower cost than the ISO. They could offer FTRs, for example, due to specialization and consequently greater expertise and/or economies of scale. Such financial instruments are a natural extension of the risk products of other industries and markets. A private party can hedge itself in the day-ahead or real-time locational price market of the ISO. For example, a generator in the position to produce valuable counterflows can safely sell private point-to-point FTRs as either options or obligations up to its expected generation capacity (assuming a radial line). These FTRs can be traded freely among traders whether or not those traders plan to schedule precisely the same point-to-point transactions, and they will have value because they are financial instruments that can be used for hedging. For real-time operations, the generator submits bids for its generation to the ISO. When counterflows are valuable so that the generator must pay out under the FTRs it provided, the local spot prices will be high and the generator will make money in the spot market. The traders holding the private issued FTRs will receive payments from the generator that will offset some or all of the congestion rents they must pay in the spot market.

9.9 Conclusions

This chapter has demonstrated the key issues associated with the provision of FTR obligations and options. In particular, the ISO must conduct an analysis of revenue adequacy, because the maximum volume of FTRs (both obligations and options) will vary with the capacities and contingencies. In a three-bus network, the maximum volume associated with an issue of a single FTR is determined by the shift factor matrix elements and transmission line capacities. It has also shown the alternative relationship for the maximum volume, congestion rent and locational prices. Due to counterflows a higher volume of FTRs might be issued between certain buses.

Conversely, a lower volume of options than obligations must be issued because they do not create counterflows. This work has also taken into account the proceeds from the FTR auction and demonstrated that a higher volume might be issued. Uncertainty associated with congestion gave the ISO an uncertain cash flow, composed of the congestion rent and payments to the FTR holders. As a tool for risk management any provider could utilize the VaR approach. The VaR shows that the greatest potential loss occurs when FTRs with the highest expected payments are issued and the lowest when FTRs with the lowest expected payments are issued. Private parties would not have to fulfill the simultaneous feasibility test and might buy insurance in the market to hedge any risks associated with providing FTRs.

Appendix

This appendix derives the shift factor matrix elements (or PTDFs) for the three-bus network with identical lines. The net injection (or net generation) of power at each bus is given by P_i. The following relationship between the net injection, the power flows P_{ij} and phase angles θ_i is:

$$P_i = \sum_j P_{ij} = \sum_j \frac{1}{x_{ij}}(\theta_i - \theta_j) \tag{9.41}$$

where x_{ij} is the line inductive reactance in per unit. Furthermore, we can write power flow equations as:

$$\begin{bmatrix} P_1 \\ P_2 \\ P_3 \end{bmatrix} = \begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix} \begin{bmatrix} \theta_1 \\ \theta_2 \\ \theta_3 \end{bmatrix} \tag{9.42}$$

The matrix is called the susceptance matrix. The matrix is singular, but by declaring one of the buses to have a phase angle of zero and eliminating its row and column from the matrix, the reactance matrix can be obtained by inversion. The resulting equation then gives the bus angles as a function of the bus injection:

$$\begin{bmatrix} \theta_2 \\ \theta_3 \end{bmatrix} = \begin{bmatrix} 2/3 & 1/3 \\ 1/3 & 2/3 \end{bmatrix} \begin{bmatrix} P_2 \\ P_3 \end{bmatrix} \tag{9.43}$$

The shift factor matrix element is the fraction of the amount of a transaction from one bus to another that flows over a given line. H_{ijmn} is the fraction of a transaction from bus m to bus n that flows over a transmission line connecting bus i and bus j. The equation for the H is:

$$H_{ijmn} = \frac{x_{im} - x_{jm} - x_{in} + x_{jn}}{x_{ij}} \tag{9.44}$$

where x_{ij} is the reactance of the transmission line connecting bus i and bus j and x_{im} is the entry in the i^{th} row and the m^{th} column of the bus reactance matrix. For example we find the following elements of H:

$H_{1212} = 2/3$, $H_{1213} = 1/3$, $H_{1223} = -1/3$,
$H_{1313} = 2/3$, $H_{1323} = 1/3$, $H_{1312} = 1/3$
$H_{3232} = 2/3$, $H_{3213} = -1/3$, $H_{3212} = 1/3$

10 Effect of losses on area prices in the Norwegian electricity market

This chapter contributes to the understanding of how bus and area prices are affected by losses and congestion. Recent papers have described area pricing to include bus prices that are equal within in a price area or zone. According to present Norwegian practice, the bus prices within a price area differ by an amount that is due to losses. We use a full AC optimal power flow model to illustrate this. Moreover, it is demonstrated that the combined effect of transmission congestion and losses may yield a substantial change in individual bus and area prices compared with a situation with no congestion or losses.

10.1 Introduction

This work assesses the simultaneous effects of transmission congestion and losses on the bus prices in an electricity market. A model for calculating area prices in the Norwegian market was developed in Bjørndal and Jørnsten (2001). The authors used a linear DC model (assuming no losses) and modeled area pricing by requiring that all bus prices within a price area should equal. This does not reflect current practice in Norway. The nodal (or bus) prices differ by an amount that is due to losses. Furthermore, the grouping of buses belonging to the same area depends on both transmission congestion and losses. In this chapter we use MATPOWER (Zimmerman and Gan, 1997) and (Kristiansen, 2003b) to calculate the impact of losses on the bus and area prices and demonstrate that ignoring losses may lead to incorrect area prices and inefficient utilization of scarce transmission resources.

10.2 Background

The deregulation of the Norwegian electricity market started with the Energy Act in June 1990 and was effective from January 1991. Competition in generation and sales of electricity was introduced together with separation of distribution and transmission services. Electricity is traded at Nord Pool or bilaterally, while transmission services are provided by the main transmission system operator (Statnett) and is a regulated natural monopoly. Statnett defines geographical price areas within Norway based on predicted generation, load and transmission capacity. The price areas are used in the day-ahead market when transmission congestion is present. Statnett manages intra-area transmission congestion by purchasing (increasing generation or load) and selling (decreasing generation or load) electricity in the real-time market. For a further introduction to the Norwegian and Nordic electricity markets, the reader is referred to Nord Pool (2002a, 2002b and 2002c).

The Norwegian transmission tariff for the central grid consists of both a variable and a residual term (Statnett, 2003). The purpose of the variable term is to contribute to optimum operation of the system. However, it might also have some impact on investment decisions. The residual term should have no (or minimal) impact on operation. The main purpose is to cover the residual cost without affecting operational decisions. The variable term in the tariff covers only 10-20% of the total grid costs. The remaining cost (80-90%) must be covered by the residual term.

The variable term consists of both an energy charge associated with losses and a capacity or congestion fee associated with transmission congestion. The energy charge is based on marginal loss factors for every bus, while the capacity fee is calculated as the difference between the area price and System Price (the unconstrained price for the Norwegian, Swedish and Finnish power markets).

The objective of the energy charge is to promote efficient utilization of the central grid. Furthermore, it should reflect the marginal losses in the power system caused by the players, and give incentives for adjustments in the short and long-run.

At buses where there are both injections and withdrawals, marginal loss factors are symmetric. Currently there are 168 exchange points in the grid. The marginal loss factor is limited to ±10% and calculated six times annually (each factor has a duration of 8-20 weeks) and is differentiated between day and night (including weekends).

The energy charge is calculated by multiplying the marginal loss factor in every injection or withdrawal point and the System Price. Therefore it represents the marginal costs associated with losses.

Injections or withdrawals that have a relieving impact on the central grid contribute to a reduction of the losses. In such cases the marginal loss factor is negative and therefore the energy charge is negative. The user is then paid for injections or withdrawals. In regions with a high generation surplus there will be a relatively high positive marginal loss factor for injections and a corresponding negative marginal loss factor for withdrawals.

Area pricing entails that several buses are grouped together and the price differentials between different areas are calculated by simplified models. In some versions of area pricing, the area prices are calculated by requiring that buses within the same area should have identical prices that equal the area price. However, this is not the case with area pricing in Norway. Here, the bus prices differ from the area price by an amount that is due to losses as illustrated by the formula:

$$p_i = AP_i \cdot (1 + ml_i) \qquad (10.1)$$

where p_i, AP_i, and ml_i are the bus price, area price, and marginal loss factor respectively. The marginal loss factor may be negative or positive.

10.3 Methodology

The Norwegian network is meshed and therefore a 3-bus network is used in our model simulations. As mentioned some zonal price models calculate the zonal prices by including a constraint that requires all bus prices within a zone to be equal. However, area pricing does not work like this in Norway and therefore an AC optimal power flow (OPF) is used to study the joint impact of losses and congestion on area prices.

We first run a simulation for the entire 3-bus network with a transmission constraint on one line. At every bus there is either load or generation. The resulting prices will reflect the marginal costs of the generators that are not at their minimum or maximum output or the marginal benefit to load. The price at the swing bus will reflect its marginal cost. The other bus prices will differ because of transmission congestion and losses. As a benchmark a DC OPF is run and it demonstrates that the joint interaction of transmission congestion and losses have substantial impact.

In order to model area prices the network is divided in two areas and the exchange of power between the areas is modeled by introducing dummy buses with generation or load that represents export/import of power to the areas. In each area there is a swing bus that will reflect the marginal cost at that location. Bus prices within each area will differ because of losses. The price difference between the areas will equal the difference in the marginal costs of the swing buses.

Figure 10-1 shows a 6-bus transmission network and two potential area divisions. The black arrow indicates a transmission constraint on line 1-4. This constraint will have different impacts on the bus prices in the two respective areas when it is binding. For example, the bus 6 price may be totally different when a DC or an AC OPF is run. The change depends on the per unit magnitude of resistance relative to reactance. Moreover, running a DC and an AC OPF may therefore result in different bus prices and any criterion based on grouping buses with similar bus prices into an area may lead to inefficiencies. How to analytically determine the grouping of buses in areas that give maximum social welfare is still an unresolved problem (Bjørndal and Jørnsten, 2001). The joint interaction of losses and transmission congestion must be taken into account as will be demonstrated, because bus prices may be different in the DC and AC cases. It may also lead to wrong incentives to electricity market players both in the short and long-run.

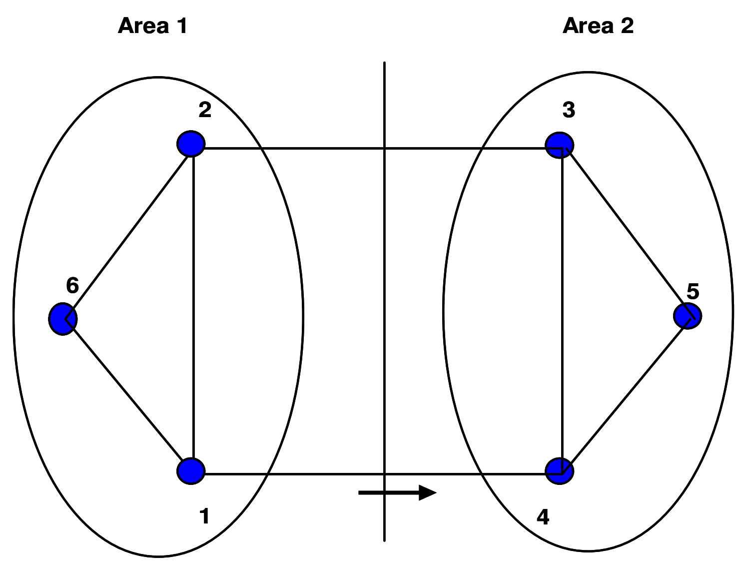

Figure 10-1. Illustration of the transmission network with a transmission constraint on line 1-4.

10.4 MATPOWER optimization

In order to calculate the impacts of losses, MATPOWER was used to calculate the bus prices. The cost data are given in Table 10-1 where the cost functions are of type $c_i P^2$ and P is generation output. In MATPOWER it is only possible to specify inelastic load data and we fixed the net loads as shown in Table 10-1. The focus is on the real or active power flows and net loads because there is no market for reactive power. In calculating the area prices, Equation (10.1) is not considered explicitly as a constraint in the model formulation. However, losses will be considered because an AC OPF is run.

Assume that transmission capacity is constrained on line 1-2 with 27 MW (including both active and reactive power flows) in the network in Figure 10-2. An AC OPF was run for the system in Figure 10-2 with resistance 0.001 per unit and reactance 1 per unit. For the bus 3 with net load, zero active generation was forced by setting the upper generation capacity equal to zero. Buses 1 and 2 with net generation did not have any binding constraints on generation capacities. The results for the entire transmission network consisting of areas 1 and 2 are shown in Table 10-2. Likewise, a DC OPF was run to make a comparison of the effects of losses on the bus prices. The results are shown in Table 10-3.

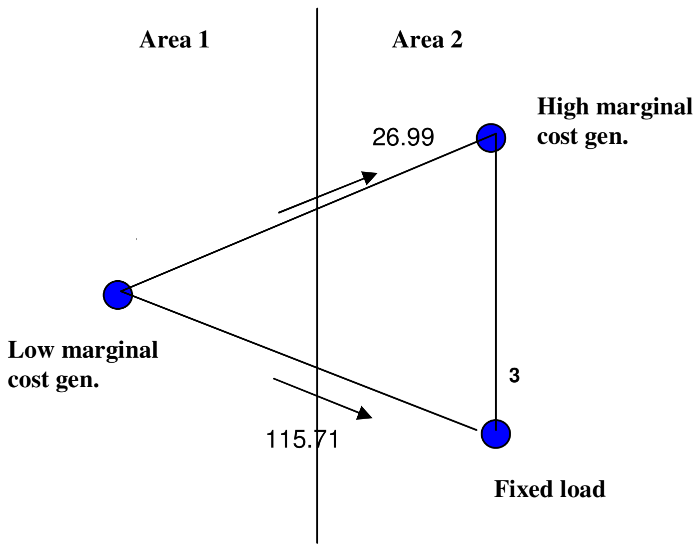

Figure 10-2. Illustration of the transmission network with a transmission constraint on line 1-2. The real power flows between the two areas 1 and 2 are indicated.

There are differences in bus prices when we compare the AC and DC OPF results. For example the bus 2 price increased with 0.98 \$/MWh when ignoring losses. Likewise bus price 3 increased with 5.08 \$/MWh.

Additionally, we observe the joint interaction between transmission congestion and losses in the transmission network. The two adjacent buses 1 and 2 have a price differential of approximately 28.8 \$/MWh. Similar results are obtained for buses 2 and 3 (-14.2 \$/MWh). Likewise, the 1 and 3 bus price difference is around 14.6 \$/MWh.

Table 10-1. Parameters for cost functions and fixed load.

Bus	Fixed load	Generation
		c_i
1	0	0.1
2	0	0.5
3	200	0

Table 10-2. AC OPF results with fixed load.

Bus	Bus prices $/MWh	Load MW	Generation MW	Flow	MW
1	28.540	0	142.7	1-2	26.99
2	57.371	0	57.37	1-3	115.71
3	43.139	200	0	2-3	84.36
Losses (MW)	0.07				

Table 10-3. DC OPF results with fixed load.

Bus	Bus prices $/MWh	Load MW	Generation MW	Flow	MW
1	28.330	0	141.65	1-2	26.95
2	58.351	0	58.35	1-3	114.70
3	48.224	200	0	2-3	85.30
Losses (MW)	0				

10.4.1 Case 1

To study the effects of losses and transmission congestion on area prices the system was divided in two: area 1 including bus 1, and area 2 including buses 2 and 3. The two lines 1-2 and 1-3 connecting these areas have 26.99 MW (real power) of flow from bus 1 to bus 2 (this is the constrained line) and 115.71 MW of flow from bus 1 to bus 3. One simulation was run for each area. For area 1 two dummy buses were introduced: one with a load of 26.99 MW (equals the power flow from bus 1 to bus 2) and another with a load of 115.71 MW (equals the power flow from bus 1 to bus 3). Similarly, for area 2 a dummy bus was introduced with generation of 115.71 MW and a dummy bus with generation of 26.99 MW. The two areas are illustrated in Figure 10-2.

The simulation results are shown in Table 10-4 and Table 10-5. The reactive power flows are shown in Table 10-10 in the appendix. The same simulations are shown for the DC case in Table 10-6 and Table 10-7. We observe that the power flows are almost identical to those of the original transmission network. In area 1 the bus price is around 32.9 $/MWh. The bus prices in area 2 are around 57.3 $/MWh. The bus prices in the original transmission network, however, ranged from 28.5 to 57.4 $/MWh. For area 1, the change in price at bus 1 is 4.4 $/MWh. Even more remarkable is the change in bus prices in area 2 from 43.1-57.4 $/MWh to around 57.3 $/MWh. The reason for these changes is that the generator at bus 1 in area 1 is the "incremental" generator with a marginal cost of $2 \cdot c_1 \cdot P_1 = 32.89\,\$/\text{MWh}$. Likewise, the marginal cost of the generator at bus 2 which is the "incremental" generator is $2 \cdot c_2 \cdot P_2 = 57.32\,\$/\text{MWh}$. Within area 2 bus prices differ due to losses. We also observe that the area prices in the AC case differ from those of the DC case. In area 1 the price is approximately 32.9 $/MWh and 28.3 $/MWh in the AC and DC cases respectively. Likewise, the area price in area 2 is approximately 57.3 $/MWh and 58.4 $/MWh in the AC and DC cases respectively. Hence, we see that we can get different area prices depending on whether a DC or an AC OPF is used.

Table 10-4. AC OPF results case 1 for area 1.

Bus	Bus prices $/MWh	Load MW	Generation MW	Flow	MW
1	32.891	0	164.46	1-2	26.99
Losses (MW)	0.02			1-3	137.47

Table 10-5. AC OPF results case 1 for area 2.

Bus	Bus prices $/MWh	Load MW	Generation MW	Flow	MW
2	57.318	0	57.32	2-3	84.31
3	57.326	200	0	1-2	26.99
Losses (MW)	0.02			1-3	115.70

Table 10-6**.** DC OPF results case 1 for area 1.

Bus	Bus prices $/MWh	Load MW	Generation MW	Flow	MW
1	28.33	0	141.65	1-2	26.95
Losses (MW)	0			1-3	114.70

Table 10-7. DC OPF results case 1 for area 2.

Bus	Bus prices $/MWh	Load MW	Generation MW	Flow	MW
2	58.35	0	58.35	2-3	85.30
3	58.35	200	0	1-2	26.95
Losses (MW)	0.0			1-3	114.70

10.4.2 Case 2

We made another price area division to study the effects of area pricing as illustrated in Figure 10-3. The optimal power flow results are shown in Table 10-8 and Table 10-9. The reactive power flows are shown in Table 10-11.

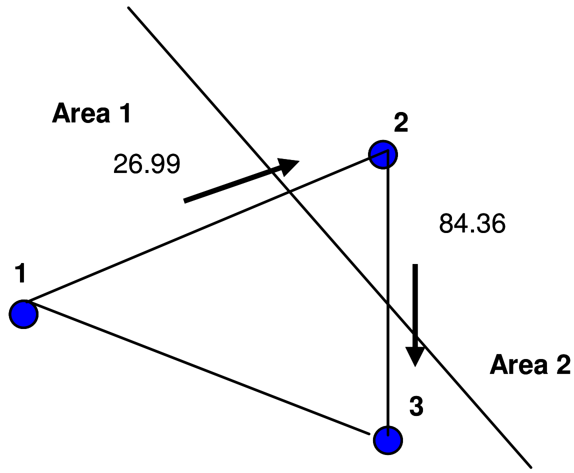

Figure 10-3. Illustration of the transmission network with a transmission constraint on line 1-2. The real power flows between the two areas 1 and 2 are indicated.

Table 10-8. AC OPF results case 2 for area 1.

Bus	Bus prices $/MWh	Load MW	Generation MW	Flow	MW
1	28.530	0	142.65	1-2	26.99
3	28.535	200	0	1-3	115.66
Losses (MW)	0.02			2-3	84.35

Table 10-9. AC OPF results case 2 for area 2.

Bus	Bus prices $/MWh	Load MW	Generation MW	Flow	MW
2	57.377	0	57.38	1-2	26.99
Losses (MW)	0.01			2-3	84.37

Under this area division bus 1 changed price from 32.9 $/MWh to 28.5 $/MWh. Likewise bus 2 price changed from 57.3 to 57.4 $/MWh. However, the bus 3 price decreased from 57.3 to 28.5 $/MWh.

10.5 Conclusions

This chapter has demonstrated that taking into account the joint interaction of losses and transmission congestion may have significant impacts on the individual bus prices. The numerical results illustrate that the bus prices differ due to both transmission congestion and losses when there is a transmission constraint binding in the full transmission network. Moreover, running a DC and an AC OPF may have different impacts on the bus prices. The current practice for area pricing in Norway was illustrated and described. Numerical results illustrate that area prices may change substantially after regrouping the buses in different price areas or when using a DC OPF rather than an AC OPF.

Appendix

Table 10-10. AC OPF reactive power flow results case 1 for the total network (TN), area 1 (A1) and area 2 (A2).

Flow	(TN) MW	(A1) MW	(A2) MW
1-2	0.84	0.60	
1-3	-140.65	15.82	
2-3	-144.04		17.58

Table 10-11. AC OPF reactive power flow results case 2 for the total network (TN), area 1 (A1) and area 2 (A2)

Flow	(TN) MW	(A1) MW	(A2) MW
1-2	0.84	0.66	-0.60
1-3	-140.65	17.33	
2-3	-144.04	6.03	5.91

11 Financial risk management in the electric power industry

This chapter describes a risk management tool for hydropower generators and its application to Norway's second-largest generation company and largest electricity consumer, Norsk Hydro ASA. The tool considers both operations scheduling and the utilization of financial contracts for risk management. Financial risks are accounted for by penalizing incomes below a reference income. The risk management problem is solved by a combination of stochastic dual dynamic programming and stochastic dynamic programming. Simulations demonstrate that lower income scenarios improve when risk aversion is introduced.

11.1 Introduction

Deregulation of the Nordic power market has increased price uncertainty, and therefore stimulated a demand for risk management tools. Each generation company schedules by using self-dispatch at the power exchange (Nord Pool). Based on aggregate bids for purchases and sales, Nord Pool calculates the market clearing price for the spot market. The spot price is the reference price for the financial contract market. Nord Pool facilitates the trade of a wide range of contracts as futures, forwards, options, and Contracts for Differences (spatial risk hedging instruments). In the over-the-counter (OTC) market, bilateral contracts are traded. These may be forward contracts, options, or load factor contracts. System coordination, monitoring and operation of the Norwegian transmission network are the responsibility of the transmission system operator (Statnett). The Norwegian power market consists of 99% hydropower with its associated uncertainty in inflows. Therefore stochastic optimization tools are utilized for long-term generation planning Fosso et al. (1999). The objective of these models is to find the optimal first-stage decision and simulate (forecast) optimal operation and income for the future. The most important risks that the Norwegian hydropower generators face are price uncertainty and quantity risks caused by uncertainty in inflows and demand. Risk management of both uncertainties is complex. Local area prices depend strongly on the precipitation and usually correlate with the local generation. There is also a correlation between the precipitation and temperature such that wet winters are warmer than normal. Hydropower generators with large reservoirs dominate the Nordic market resulting in a sequential dependence in spot price. All of these correlations must be managed by using an appropriate risk management tool. A model for integrated risk management of hydropower scheduling and contract management in a stochastic dynamic optimization framework has been developed by Mo et al. (2001a) and Mo and Gjelsvik (2001). Their model includes the possibility for future trading and use of reservoirs and futures contracts as risk management tools. The model's objective is to utilize a time separable utility function to characterize the risk attitude of the company. The solution methodology is a combination of stochastic dual dynamic programming (SDDP) (Pereira, 1989) and stochastic dynamic programming (SDP) (Gjelsvik et al., 1999).

The latest version of the model accounts for the modeling of the spot price extremes and the long-term uncertainty of futures prices. As mentioned in Gjelsvik et al. (1999) it suggests less trading when dynamic hedging[139] is allowed. The test results

[139] Dynamic hedging is a strategy that involves rebalancing hedge positions as market conditions change.

also demonstrated that the reservoir discharge strategy depends upon the company's utility function. An increased penalty term gives a more risk-averse operation of the reservoir. The tests showed that it is possible to reduce the risk considerably without reducing the expected income to the same extent. It implies that the income optimum is relatively flat. Gjelsvik et al. (1999) demonstrated that the results are highly sensitive to the internal price model used in the optimization. This resulted in the development of the price model described in Mo et al. (2001b). This chapter describes the testing of the improved model on the power system of Norway's second-largest generation company.

11.2 The model

The model has been developed by Mo et al. (2001a) and is an extension of an existing tool for medium-term hydropower scheduling described in Gjelsvik et al. (1999), where new state variables are introduced to account for future trading. An overview of the model is presented in this section. The objective in the new model is to maximize the sum of net income from trading in the futures market, sales in the spot market and the value of the water at the end of the planning period, minus penalty terms for failing to fulfill income requirements. The penalty terms penalize progressively for incomes below a user-specified limit at the end of the period. The planning period is usually two or three years with a time resolution of one week. The spot price and inflow are assumed to be known at the beginning of the week. Generation, trading of standardized futures contracts and withdrawal of load factor contracts are decided in the beginning of the weeks.[140] In Nord Pool the contracts are traded in one-week lots for the first 4-7 weeks.[141] After this contracts are traded in 4-week blocks and beyond one year in seasons. The market features are implemented in the model and the time resolution is dynamic, so that blocks are resolved into weeks and seasons are resolved into blocks as time passes, as in the actual market. Future contracts are delivered at a flat MW rate. The important calculated values are:

- Generation schedules and marginal water values for each reservoir.
- Trading schedules and marginal contract values for each standardized future contract (traded at Nord Pool).
- Income forecasts that include a realistic measure of future uncertainty.

Model definitions include:

period: the basic time step is one week so that a period may be one or more weeks
planning period: time from now up to the planning horizon (usually 2 to 3 years) used in the model
income period: the period used for measuring income, usually annually
k week in the planning period
t week in the futures market (contract period), $t > k$
N number of weeks in the planning period
$E_{P,v}$ expectation operator applied to the distributions of price (P) and inflow (v)
$Sp(k)$ energy exchanged at spot market price in week k (GWh)
$P(k)$ average spot price in week k (NOK/MWh)
N_{prof} number of income periods
$P_{st}(J)$ first week in income period J

[140] The state variables describing reservoir levels, position in the futures market and accumulated income are referred to the beginning of the week.
[141] This is referring to the financial market structure existing until fall 2003.

$P_{sl}(J)$ last week in income period J
$I(k,J)$ accumulated income for income period J in week k (NOK)
$Pen()$ penalty function for failing to fulfill the income requirements
$R(x(N)$ value of water remaining in week N (NOK), estimate obtained from long-term scheduling
$S(k,t)$ sales committed in week k for future week t (GWh)
$K(k,t)$ purchase committed in week k for future week t (GWh)
$B(k,t)$ accumulated balance (sum of commitments) in week k for future week t (GWh)
$pf(k,t)$ contract price in week k for delivery in future week t (NOK/MWh)
Δp transaction costs (NOK/MWh)
$x(k)$ vector of reservoir levels in week k (Mm^3)
$x_{max}(k)$ vector of maximum reservoir levels in week k (Mm^3)
$x_{min}(k)$ vector of minimum reservoir levels in week k (Mm^3)
$u(k)$ vector of discharges in week k (Mm^3)
$u_{max}(k)$ vector of maximum discharges in week k (Mm^3)
$u_{min}(k)$ vector of minimum discharges in week k (Mm^3)
C matrix describing the system topology
$G()$ conversion function from discharge vector to generation (GWh)
$v(k)$ vector of inflows for week k (Mm^3)
$v_n(k)$ normalized inflow vector in week k
$\sigma_v(k)$ standard deviation of inflow week k
$\mu_v(k)$ expected inflow in week k
$\varepsilon_v(k)$ noise-term which is normally distributed $N(0,\Omega)$ where Ω is the covariance of the noise-term
A inflow matrix containing correlation in inflow between week k and $k+1$

The objective function is:

$$\begin{aligned} Max\ E_{P,v} \Bigg\{ & \sum_{k=1}^{N} Sp(k)P(k) - \sum_{k=1}^{N-1}\sum_{t=k+1}^{N} K(k,t)(pf(k,t)+\Delta p) \\ & + \sum_{k=1}^{N-1}\sum_{t=k+1}^{N} S(k,t)(pf(k,t)-\Delta p) - \sum_{J=1}^{N_{prof}} Pen(I(P_{sl}(J),J)) + R(x(N)) \Bigg\} \end{aligned} \tag{11.1}$$

The water balance, reservoir and discharge constraints are:

$$x(k+1) = x(k) - Cu(k) + v(k) \qquad k = 1,..,N \tag{11.2}$$

$$x_{\min}(k) \le x(k) \le x_{\max}(k) \qquad k = 1,..,N \tag{11.3}$$

$$u_{\min}(k) \le u(k) \le u_{\max}(k) \qquad k = 1,..,N \tag{11.4}$$

The contract balance for any future week t is updated for every week in the planning period k:

$$B(k+1,t) = B(k,t) + K(k,t) - S(k,t) \qquad k = 1,..,t-1 \tag{11.5}$$

The spot market balance equals:

$$Sp(k) = G(u(k)) + B(k,k) \qquad k = 1,..,N \tag{11.6}$$

Accumulated income caused by trading in the futures market (accounted as physical contracts) and income due to trading in the spot market are given by:

$$\begin{aligned} I(k+1,J) &= I(k,J) + \sum_{t=max(P_{st}(J),k+1)}^{P_{sl}(J)} S(k,t)(pf(k,t) - \Delta p) \\ &- \sum_{t=max(P_{st}(J),k+1)}^{P_{sl}(J)} \left(K(k,t)(pf(k,t) + \Delta p) \qquad k = 1,..,N \right. \\ I(k,J) &= I(k,J) + Sp(k)P(k) \quad \text{if } P_{st}(J) \le k \le P_{sl}(J) \end{aligned} \tag{11.7}$$

The initial contract portfolio gives *B(0,t)* and *I(0,J)* for all *t* and *J*. Each load factor contract is modeled as a reservoir with a given initial energy amount and a power station efficiency of 1.0 and an upper MW rate. Equations (11.2) and (11.4) therefore apply. The inflow is zero except for the time of initialization or renewal. The model suggests the optimal use of existing load factor contracts, but does not give any decision support whether or not to enter into new load factor contracts. Accounting of futures contracts are as for physical contracts and affects which income states that are updated when trading occurs in week *k* for future week *t.*

The penalty function describes the company's risk attitude and corresponds to a utility function. It is illustrated in Figure 11-1. Incomes below a reference income (the company's income target) in each income period are penalized in the objective function by subtracting a penalty cost. The cost is zero for incomes above the reference income. The penalty function must be defined by a reference income and marginal penalty (i.e. the slope of the function) for all income periods and may differ from one income period to another. It may also have two or more segments as illustrated in Figure 11-1. If the penalty function is subtracted from the income, the result is a utility function demonstrating that the company is risk neutral for incomes above a certain level. The penalty function is assumed to be convex and must be specified and calibrated by the user of the model. In this work incomes below the 25 percentile are penalized with different marginal penalties. Only two segments are included in the penalty function.

Hydropower plants have an infinite horizon and therefore a function that values the water at the end of the planning period is needed. The function is constructed from an aggregated long-term model system and is a function of total storage.

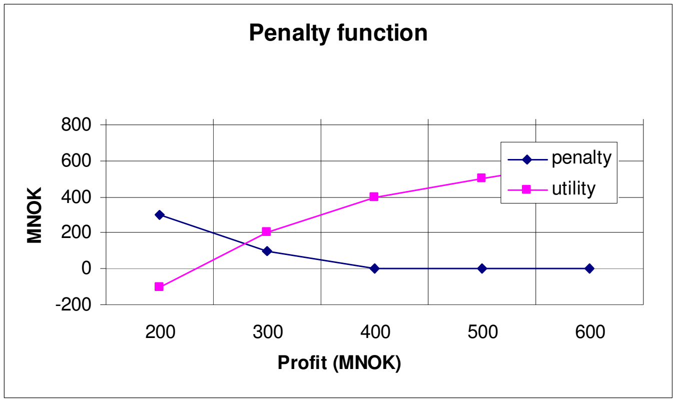

Figure 11-1. Example penalty function and the associated utility function for a risk averse agent.

11.2.1 Inflow model

Uncertainty is taken into account by assuming stochastic future spot market prices and inflows to reservoirs. The inflows to the reservoirs are modeled as a multivariable first order autoregressive model. Input data are historical inflows. The model described in Røtting and Gjelsvik (1992) introduces additional state variables to Equations (11.1)-(11.7). With a weekly resolution there will usually be a certain autocorrelation in the inflow, $v_n(k)$. A simple model describing this is the lag-one autoregressive process. A normalized inflow model is used:

$$v(k) = \sigma_v(k)v_n(k) + \mu_v(k) \tag{11.8}$$

$$v_n(k+1) = A \cdot v_n(k) + \varepsilon_v(k+1) \tag{11.9}$$

A is the auto-regression matrix, and $\varepsilon_v(k+1)$ is a stochastic term that is uncorrelated from one week to the next. With no auto-correlation $v_n(k+1) = \varepsilon_v(k+1)$. This inflow model is easily handled by the SDDP algorithm. The elements of A and the distribution of $\varepsilon_v(k+1)$ must be determined from the observed inflows. To apply the SDDP algorithm, a set of discrete inflow values is used at each week resulting in a finite number of possible reservoir sequences. Inflow series for regulated and unregulated inflows are treated similarly.

11.2.2 Price model

A first order discrete Markov price model is simple and applicable in a stochastic optimization framework. The price in one time step depends on the price in the previous time step. However, the Markov price model does not always capture all of the statistical properties of the price scenarios. In some cases it is observed that the mean reverting properties of the Markov model are stronger than what is observed for simulated extreme prices.

The general price model structure is shown in Figure 11-2. For every time step, there is a given number of price nodes, $P_i(k)$. Transition probabilities $p_{ij}(k)$ are linking the price nodes where $p_{ij}(k)$ is the probability that the price is $P_j(k+1)$ at time step k+1 given that it was $P_i(k)$ at time step k. A process identifies what prices belong to the same node and estimates the transition probabilities from Norsk Hydro's statistical price forecast (see Mo et al., 2001b).

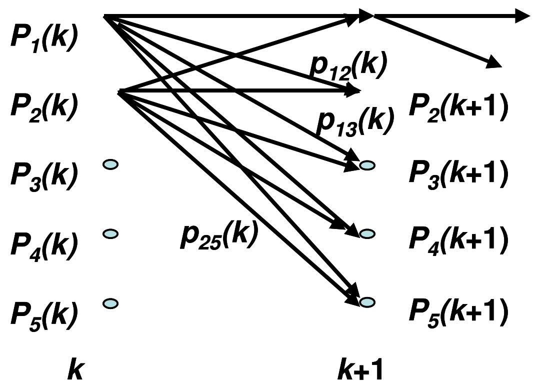

Figure 11-2. Price model structure.

An important assumption is that the price of the futures contract equals the expected spot price in the delivery week t conditioned on the spot price in trading week k:

$$pf(k,t) = E(P(t) \mid P(k)). \tag{11.10}$$

Here it is assumed that the futures market gives an unbiased estimate of the expected future spot market prices. The spot price model is used to compute the conditional probability distribution of $pf(k,t) = E(P(t) \mid P(k))$ and therefore the futures market price at decision time step k and future delivery week t.

In the forward market, prices of contracts with delivery up to several years ahead vary from week to week. To incorporate this, the price model has been expanded with new nodes and transition probabilities that model the probability of shifts in futures prices (Mo et al., 2001b). The price nodes consist of the original nodes and new nodes calculated as the original ones plus/minus a price shift. The new transition probabilities are calculated by combining the original ones and the probability of a price shift. The price shift model is symmetric with expected value zero so that the expected price of the original price model is unchanged. The improved price model is similar to a multi-factor price model.

11.3 Solution methodology

The model formulation in Equations (11.1)-(11.7) is a stochastic dynamic optimization problem. The solution methodology is a combination of SDDP (Pereira, 1989) and SDP (Gjelsvik et al. 1999) adapted to the model extensions. There is no reduction of the state space, and a power system with many reservoirs and load factor contracts will have a substantial computational time.

A system state vector in week k is defined as:

$$z(k) = \left[x^T(k), B(k,k+1),.., B(k,N), I(k,1),...I(k,N_{prof}), P(k) \right]^T \tag{11.11}$$

and a decision vector as:

$$y(k) = \left[u^T(k), S(k,k+1),....,S(k,N), K(k,k+1),...K(k,N)\right]^T \tag{11.12}$$

With these definitions the objective is written as:

$$Max\ E_{P,v}\left\{\sum_{k=1}^{N} L_k(z(k), y(k)) + R(z(N))\right\} \tag{11.13}$$

where $L_k(z(k), y(k))$ is the immediate return from stage *k*, including penalties represented by Equation (11.1). Assuming that transition probabilities at stage *k* are independent of the previous states *z(k*-1*)*, *z(k*-2*)*, ..., the problem can be solved by dynamic programming. The Bellman recursion equation is:

$$\alpha_k(z(k)) = E_{P,v} Max\left\{L_k(z(k), y(k)) + \alpha_{k+1}(z(k+1))\right\} \tag{11.14}$$

and is solved subject to Equations (11.2), (11.5), and (11.7) which define *z(k*+1*),* and to other relevant constraints. $\alpha_{k+1}(z(k+1))$ is the expected future return function from state *z(k+1)* to a feasible final state in the optimum manner. For the last interval we have the relationship $\alpha_N(z(N)) = R(z(N)) + Pen(z(N))$. The objective function in Equation (11.1) contains nonlinear terms, making it non-convex. To utilize a hyperplane (cuts[142]) representation of the future income $\alpha_k(z(k))$, 5-7 discrete price levels are used. The methodology is analogous to traditional stochastic dynamic programming with respect to price state. The solution algorithm is iterative. Each main iteration consists of a backward recursion using Equation (11.14) where the strategy is updated for all weeks in the planning period and a forward simulation based on the last operating strategy (described by hyperplanes). As in the SDDP method sampling in the tree of outcomes is essential. SDDP differs from SDP in that expected future incomes are represented by hyperplanes and not tables.

At each time step one builds a strategy given by hyperplanes in the "z-space." The hyperplanes are represented as constraints of the type:

$$\begin{aligned} &\alpha_{k+1} - \left(\mu_{k+1}^{j1}\right)^T z(k+1) \le \gamma_{k+1}^{j1} \\ &\dots\ \dots\ \dots\ \dots\ \dots\ \dots\ \dots \\ &\alpha_{k+1} - \left(\mu_{k+1}^{jR}\right)^T z(k+1) \le \gamma_{k+1}^{jR} \end{aligned} \tag{11.15}$$

where $\mu_{k+1}^{j1}....\mu_{k+1}^{jR}$ and $\gamma_{k+1}^{j1}....\gamma_{k+1}^{jR}$ denote the coefficients that define the *R* hyperplanes representing the expected future income function at the price point $P^j(k)$. Moreover, *z(k*+1) includes all state variables except price. The vector μ is the mean dual variable of some of the constraints in the sub-problem of (11.14) while γ is the right-hand side constant in the cuts.

[142] A set of linear constraints.

A single-transition sub-problem of Equation (11.14) under the assumption of a hyperplane representation together with the cuts Equation (11.15) and the respective constraints in Equations (11.2), (11.5), and (11.7) constitute a standard linear programming problem (with associated dual variables), which is easily solvable and gives the expected income in week k based on the hyperplanes in week $k+1$. In the backward recursion an upper limit on the income is obtained. To solve the single-transition sub-problem, a relaxation procedure is utilized. This is an effective strategy if relatively few constraints are binding at optimality. In the sub-problem $x(k)$ is known while $x(k+1)$ in the cuts (Equation (11.15)) and the bounds Equation (11.3) can be eliminated by using Equation (11.2) as described in Røtting and Gjelsvik (1992). Bounds on the reservoirs are seldom binding and may be relaxed. Also when many cuts are present most of them may be relaxed. Thus, the number of iterations in the relaxation procedure is relatively small.

The forward simulation is performed for all inflow and price scenarios. Optimal weekly generation is determined from the single-transition sub-problem, given inflow and price. The expected future income is calculated from the last backward iteration. The objective function is:

$$E_{P,v} Max\{\text{Income}(k) + \alpha_{k+1}(z(k+1))\} \tag{11.16}$$

The forward simulation gives possible non-optimal solutions that are used to calculate an indicative lower limit on expected future incomes. The same scenarios are simulated but with different state values. A cut generated for one reservoir and price level may be used by the other scenarios at the same price level because of the Markov assumption. The model includes a heuristic based on observed inflows in the forward simulation.

Convergence may be obtained when the absolute value of the difference between the upper and lower limit is comparable to the standard deviation of the upper limit. However, in practice a specified number of iterations are carried out.

11.4 Lagrange multipliers and marginal market signals

The marginal cost values determined from this model cannot be directly compared to the market price when penalty functions are active. Let the Lagrange multipliers associated with the contract balance (Equation (11.5)) and the accumulated income due to trading in the futures market (Equation (11.7)) be $\Pi_B(k,t)$ and $\Pi_I(k,J)$ respectively. For a sale of contracts $S(k,t) > 0$ a necessary condition is:

$$\Pi_B(k,t) \le (pf(k,t) - \Delta p)(1 + \Pi_I(k,J)) \tag{11.17}$$

or

$$pf(k,t) \ge \Pi_B(k,t)/(1 + \Pi_I(k,J)) + \Delta p \tag{11.18}$$

Similarly for a purchase of contracts $K(k,t) > 0$, a necessary condition is:

$$pf(k,t) \le \Pi_B(k,t)/(1 + \Pi_I(k,J)) - \Delta p \tag{11.19}$$

$\Pi_I(k,J)$ is called the income penalty multiplier associated with week k in the planning period and J is the index of the income period that contains week t.

Associate λ with the spot market balance (Equation (11.6)). To sell in the spot market we must have:

$$P(k) \geq \lambda/(1+\Pi_I(k,J)) \tag{11.20}$$

In the case $\Pi_I(k,J)=0$ we find the usual condition for sales in the spot market. When the market price is higher than the water value, sales are suggested. When $\Pi_I(k,J)>0$, the Lagrange multiplier associated with the spot market balance (λ) is modified such that risk adjusted water values are obtained.

11.5 Test system description

Norway's second-largest power producer, Norsk Hydro ASA operates 21 power stations and has ownership in 25 others. The total installed capacity is 1740 MW; the average annual generation is 8.6 TWh (11.3 TWh in 2000). Figure 11-3 shows the respective annually generation in the main five watercourses.

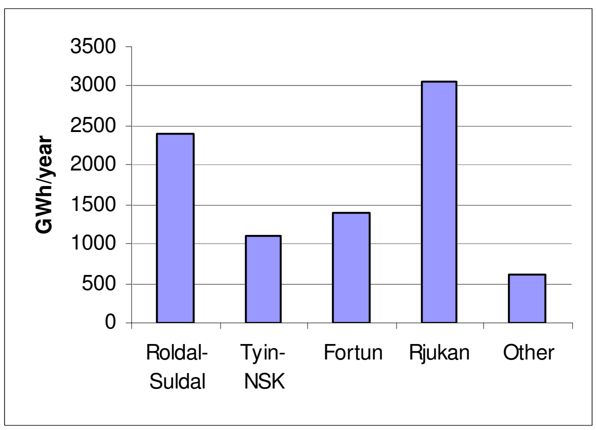

Figure 11-3. Norsk Hydro's annual total power generation.

Norsk Hydro's fictive contract portfolio consists of a flat sales contract with a volume of 8.76 TWh/year and a price of 21.49 EUR/MWh, and three load factor contracts with the specifications shown in Table 11-1. The load factor contracts span different income periods (i.e. the years 2001, 2002 and 2003) and seasons, which makes the problem complex to solve. The user of the model is free to specify the length of the contract durations. The model parameters are given in Table 11-2.

Table 11-1. Load factor contract specifications.

LFC	Period	Price (EUR/MWh)	Initial volume (GWh)	Min volume (GWh)	Max volume (GWh)
1	44-78	22.08	491	0	491
2	79-130	22.08	664	0	664
3	131-156	22.08	332	0	332
	Min rest volume (GWh)	Max rest volume (GWh)	Min withdrawal (GWh)	Max withdrawal (GWh)	
1	0	0	0	15.288	
2	0	0	0	15.288	
3	0	0	0	15.288	

Table 11-2. Different parameters used in the model.

Parameter	
Generation cost	5844160 EUR monthly
Transaction cost	0.195 EUR/MWh
Maximum weekly transaction	50 GWh/week
Probability of price shift	0.1
Value of price shift	0.481 EUR/MWh
Initial contract balance in each week	-168 GWh/week

There are three income periods, one for the period, weeks 44-52 (the rest of year 2001), and one each for weeks 53-104 (2002) and 105-156 (2003). The locked income in the futures market for each of the income periods is EUR 16.56, 102.26 and 102.40 million, respectively. The value of the price shift was estimated from the seasonal forward Summer 2001 contract prices at Nord Pool in the period May 2 to December 29, 2000. The average price of the forecast used in the simulations is shown in Figure 11-4. The price forecast has 240 scenarios.

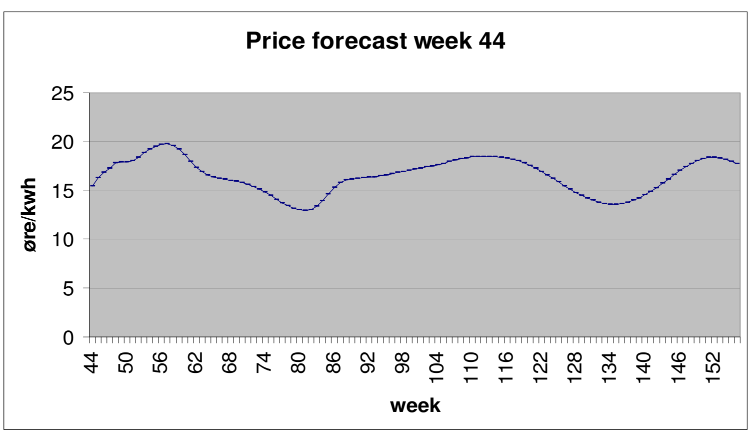

Figure 11-4. Average price forecast at week 44 used in the simulations (1 øre/kWh is approximately equal to 1.3 EUR/MWh).

11.6 Model studies

The integrated risk management model calculates values used for making decisions today, such as discharge of water and hedging in the futures market. It also simulates forecasts for possible futures given by price scenarios and associated local inflow scenarios after the optimal strategy is found.

The model has been run for five different cases for the penalty function. The penalty function is similar in all income periods. A marginal penalty of 1.0 means that if the expected income is EUR 100 million below the reference income, the company is charged a penalty of EUR 100 million. A two-segment penalty function is used with different marginal penalties or slopes corresponding to different risk preferences.

Case 1: Risk neutral
The base case is the risk neutral case. In this case it is unnecessary to optimize the generation and the contract portfolio simultaneously.

Case 2: Risk-averse, marginal penalty 0.5
In this case income results below the 25 percentile are penalized with marginal penalty 0.5.

Case 3: Risk-averse, marginal penalty 1.0
In this case income results below the 25 percentile are penalized with marginal penalty 1.0.

Case 4: Risk-averse, marginal penalty 5.0
In this case income results below the 25 percentile are penalized with marginal penalty 5.0.

Case 5: Risk-averse, without dynamic hedging
The penalty function is the same as in case 2 but trading in the futures market is not allowed.

In each run the received income results for 240 different scenarios (with equal probability) are based on Norsk Hydro's price forecast. The calculated expected income for each of the periods is shown in Table 11-3. The results for income period 3 should not be overemphasized, since the planning period is rolling. Only the simulation results for weeks 1-52 are used in practice.

The risk neutral case (case 1) has the highest expected total income, EUR 379.49 million, followed by cases 2 and 5. The expected income does not change substantially in the different cases, so the optimum is relatively flat. The standard deviation for the first period has decreased by half the amount from the risk neutral case for all the other cases. The decrease is less in other periods; cases 4 and 5 show the most significant change. The end reservoir is highest for the risk neutral case and decreases with increasing risk aversion (except case 3).

Table 11-3. Simulated income (MEUR) for cases 1- 5.

	Case 1	Case 2	Case 3	Case 4	Case 5
Average income period 1	28.61	30.25	31.93	30.92	31.83
Std. dev.	8.85	4.86	5.40	4.96	4.86
Average income period 2	140.70	139.98	136.35	142.11	140.96
Std. dev.	25.81	22.46	19.60	20.60	21.56
Average income period 3	130.78	130.46	129.72	126.68	130.03
Std. dev.	29.70	27.73	26.40	25.69	23.51
End reservoir	79.35	74.77	76.70	72.73	73.16
Expected total income	379.49	375.44	374.68	372.43	375.31
Min income period 1	3.03	23.04	25.12	24.91	23.05
Min income period 2	85.54	88.13	109.09	107.89	96.09
Min income period 3	43.77	26.01	10.62	25.51	75.18
Max income period 1	43.79	42.86	46.01	43.34	43.90
Max income period 2	208.86	207.06	199.26	205.94	205.15
Max income period 3	221.50	221.31	217.22	211.66	217.25
Expected trading income	0.00	-2.10	-1.42	-1.40	0.00
Expected transaction cost	0.00	0.44	0.45	0.55	0.00
Expected penalty	0.00	1.57	1.42	12.52	0.95

Table 11-3 shows that the minimum income scenarios[143] have improved in income periods 1 and 2. For income period 1, cases 3 and 4 show the most improvements: from EUR 3.03 million to about EUR 25.12 and EUR 24.91 million respectively. For income period 2, case 3 shows the best improvement of the minimum value from EUR 85.54 to EUR 109.09 million. In short all minimum income scenarios in income periods 1 and 2 have improved significantly from the risk neutral case, while the minimum income in period 3 decreased in most cases, except for case 5. The maximum income scenario in period 1 is highest in case 3, and in the other periods the maximum income scenario has the same order of magnitude in most of the cases.

Table 11-4. Simulated generation (GWh) for all cases.

Period	Case 1	Case 2	Case 3	Case 4	Case 5
Winter 2 2001	1840.4	1949.2	1935.6	1970.6	2001.7
Winter 1 2002	3255.7	3150.1	3153.3	3134.8	3155.7
Summer 2002	3912.0	3927.1	3916.9	4041.8	4018.1
Winter 2 2002	2191.6	2254.3	2230.9	2263.3	2297.0
Winter 1 2003	2966.3	2900.9	2877.1	2653.5	2783.8
Summer 2003	3871.6	3939.9	3935.6	3997.1	3899.2
Winter 2 2003	2371.5	2468.1	2488.9	2511.0	2500.4
Total	20409.1	20589.5	20538.2	20572.1	20656.0

The expected trading income (or loss) is lowest in case 3 (moderate penalty) and zero in cases 1 and 5 because there is no trading in the futures market. The transaction and penalty costs are highest in case 4.

[143] The minimum income scenario is the value of the scenario with lowest income of the 240 scenarios.

The hydropower generation in the different cases and periods is shown in Table 11-4. The total generation is lowest in case 1 and highest in case 5. This is as expected because hedging is not allowed in case 5. The only way the producer can fulfill the income requirement is to use physical generation. With increasing risk aversion the generation in the period Winter 2 2001 is increasing relative to case 1. The reason is that when a penalty for failing to fulfill the income requirement is introduced, it is cheaper to use hydropower generation than hedging in the futures market to meet the budget for the year 2001. The results are more ambiguous for the other seasons.

The income penalty multipliers for all runs are shown in Table 11-5. The multipliers are highest in the first period for cases 1-4, meaning that the model emphasizes the fulfillment of the income requirement more in this period compared to the other periods.

Table 11-5. Income penalty multipliers for the initial week.

	Income period 1	Income period 2	Income period 3
Case 1	0	0	0
Case 2	0.036	0.020	0.003
Case 3	0.024	0.002	0.017
Case 4	0.030	0.015	0.019
Case 5	0.030	0.023	0.041

Table 11-6. Marginal water values and marginal values of load factor contracts (LFCs) in EUR/MWh in week 44 for all cases.

	Case 1	Case 2	Case 3	Case 4	Case 5
Møsvann	19.09	20.77	20.05	20.73	18.40
Middyrvann	20.52	20.88	21.45	19.65	18.82
Votna	19.92	20.13	20.67	18.64	17.82
Valldalen	19.49	19.53	20.21	17.51	19.90
Røldalsvann	19.82	19.56	20.36	16.48	19.84
Sandvann	21.49	22.81	21.99	20.82	22.35
Tyinsjøen	19.12	19.45	19.92	17.99	18.44
Øvre Herva	22.02	23.05	22.80	23.62	22.84
Storevatn	21.59	23.08	22.63	22.96	22.65
Herva	22.14	23.43	22.79	22.97	23.01
Skålavatn	22.14	23.43	22.79	22.97	23.01
Fellvann	19.16	20.04	19.46	16.79	18.40
Sokumvann	18.33	19.39	18.76	15.61	17.61
LFC 1	17.93	18.20	18.28	18.29	18.42
LFC 2	17.13	17.44	17.40	17.35	17.48
LFC 3	18.14	18.18	18.40	18.45	18.83

The marginal risk adjusted water values and contract values for some of the most important reservoirs in Norsk Hydro's total system in the initial week are shown in

Table 11-6. To use the marginal water values as a decision support tool, they must be divided by one plus the income penalty multipliers for income period 1.

Table 11-7. Marginal future contract values (EUR/MWh) in week 44 all cases.

Futures contracts	Case 1	Case 2	Case 3	Case 4	Case 5
Week 45	21.90	22.66	22.55	22.52	22.53
Week 46	22.62	23.38	23.37	23.24	23.25
Week 47	23.18	23.92	23.83	23.79	23.79
Week 48	23.86	24.57	24.47	24.44	24.43
Block 1	24.00	24.57	24.58	24.55	24.55
Block 2	25.49	25.99	25.94	25.86	26.05
Block 3	25.34	25.83	25.78	25.70	25.90
Block 4	22.51	22.95	22.89	22.82	23.00
Block 5	21.16	21.57	21.52	21.45	21.62
Block 6	20.47	20.86	20.80	20.74	20.91
Block 7	19.04	19.39	19.34	19.27	19.43
Block 8	17.34	17.65	17.61	17.56	17.69
Block 9	17.32	17.62	17.59	17.53	17.66
Block 10	20.09	20.40	20.38	20.31	20.43
Block 11	21.12	21.43	21.39	21.35	21.45
Season 1	22.08	22.39	22.35	22.31	22.39
Season 2	23.62	23.69	24.01	24.06	24.64
Season 3	19.36	19.40	19.62	19.68	20.06
Season 4	23.18	23.22	23.43	23.51	23.83

As for the marginal water values the marginal future contract values shown in Table 11-7 must be adjusted with an income penalty multiplier referred to the actual income period. Trading of futures contracts in the model occurs when the difference between the corrected marginal contract value and the market price for that specific futures contract exceeds the transaction cost. A positive difference indicates purchase; a negative difference indicates sale.

The expected trade (sale) of futures contracts in the first week (week 44) for all future weeks is shown for all cases in Table 11-8. The trade is zero for all weeks in 2002 and 2003, and is highest for cases 2 and 3 in the rest of the weeks in year 2001. When risk aversion and hedging are introduced, there is trade (sale) in the end of year 2001.

The withdrawal from the load factor contracts illustrated in Figure 11-5 shows that the withdrawal is typically high in periods with high prices (winter) and low in periods with low prices (summer). The withdrawal profiles for the different cases are relatively similar.

Table 11-8. Expected trade (sale GWh/week) for future weeks in the first week (week 44), as function of future weeks for all cases.

Futures contracts	Case 1	Case 2	Case 3	Case 4	Case 5
Week 45	21.90	22.66	22.55	22.52	22.53
Week 46	22.62	23.38	23.37	23.24	23.25
Week 47	23.18	23.92	23.83	23.79	23.79
Week 48	23.86	24.57	24.47	24.44	24.43
Block 1	24.00	24.57	24.58	24.55	24.55
Block 2	25.49	25.99	25.94	25.86	26.05
Block 3	25.34	25.83	25.78	25.70	25.90
Block 4	22.51	22.95	22.89	22.82	23.00
Block 5	21.16	21.57	21.52	21.45	21.62
Block 6	20.47	20.86	20.80	20.74	20.91
Block 7	19.04	19.39	19.34	19.27	19.43
Block 8	17.34	17.65	17.61	17.56	17.69
Block 9	17.32	17.62	17.59	17.53	17.66
Block 10	20.09	20.40	20.38	20.31	20.43
Block 11	21.12	21.43	21.39	21.35	21.45
Season 1	22.08	22.39	22.35	22.31	22.39
Season 2	23.62	23.69	24.01	24.06	24.64
Season 3	19.36	19.40	19.62	19.68	20.06
Season 4	23.18	23.22	23.43	23.51	23.83

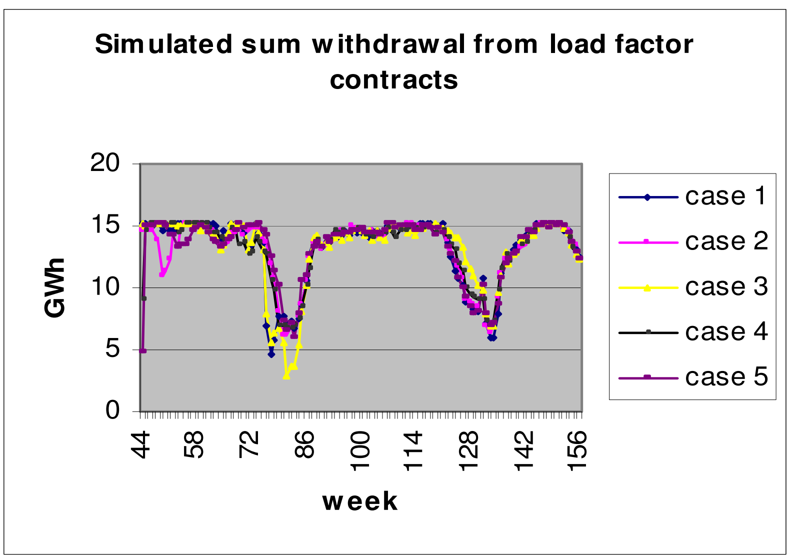

Figure 11-5. Simulated sum withdrawal from load factor contracts (GWh).

11.7 Practical issues

Practical issues should be given high priority when the system will be run in parallel with today's risk management tools. The inputs for the model simulations on

Norsk Hydro's total power system and portfolio are comprehensive. For the weekly runs, the following data are needed: reservoir levels; contract and income balance for the entire planning period; revision plans; options data; load factor contract data; and the weekly price forecast. A special program is used to extract the contract portfolio data from two databases. During testing it usually takes 1-2 hours to update all of the mentioned data. The running time for the model is about 15-20 hours on a 1 GHz CPU PC.

11.8 Discussion and conclusions

Our tests have demonstrated that it is possible to apply the model to realistic cases. The case results have shown that hydropower generation and trading in the futures market change with the risk aversion.

In general we found that the expected income decreased with increasing penalty as we expected. The minimum income scenarios in the closest income periods are reduced when risk aversion is introduced. When no hedging in the futures market is allowed, the water is moved between the different time periods (seasons) to meet the income targets.

The model gives risk adjusted water values as output and these can be used as a condition for sale in the spot market. Another result of the simulations is that the marginal contract values, when properly adjusted, can be used as signals for buying or selling in the futures market.

The expected trading observed from week 44 occurs in weeks 45-52 of year 2001 for the cases with risk aversion and hedging. Most of the withdrawals from the load factor contracts occur in the periods with high price, and the withdrawal profiles are relatively unaffected by risk aversion if the transaction costs are small (Mo and Gjelsvik, 2001).

When dynamic hedging is introduced, the simulated income uncertainty is reduced and the model offers a more realistic forecast of the associated income for a portfolio of physical generation, futures contracts, and load factors contracts. An optimization of both physical generation and the contract portfolio is necessary because the information about reservoir levels and rest volumes gives signals about changes in future position and reduces inflow risks.

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