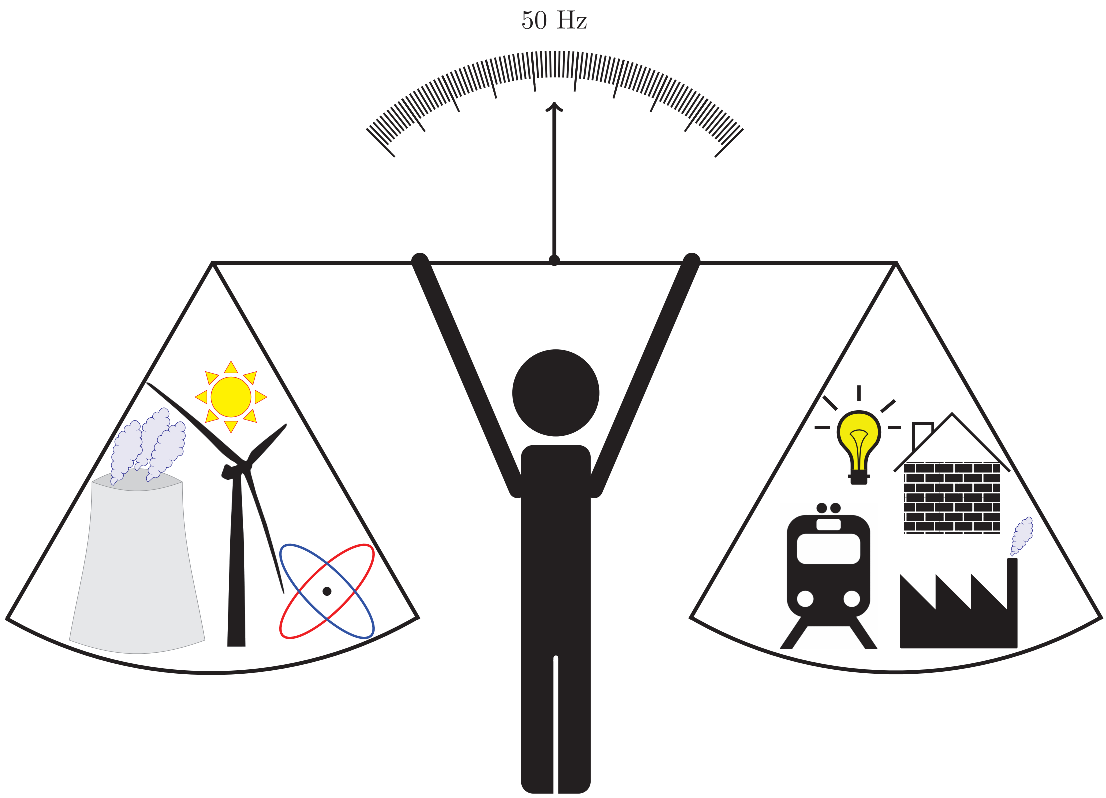

Wind Energy Curtailment for Optimal Operation of Power Systems Under Uncertainty

Master Thesis in Electric Power Engineering

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Abstract

As the penetration of wind power increases in power systems, there is a need to address the effect of wind forecasting error during the real time operation. The role of the Transmission System Operator (TSO) in electricity markets is to ensure safety and reliability of the power system. Currently, most power systems clear the spot market based on supply and demand bidding curves. Under the context of unit commitment, the objective of the TSO is to minimize the generation cost. Such an approach is usually deterministic and does not account for the uncertainties in the system.

The aim of this thesis is to formulate a mathematical model that optimizes power system operation. This is achieved by taking into account the expected cost of wind power forecasting error with wind energy curtailment. An additional aim is to compare the operational cost of the proposed optimal system operation and the current system operation in the Nordic power system. The economic value of wind energy curtailment is also evaluated. It is observed that day ahead scheduling considering the expected cost of net demand forecasting error will reduce the total cost significantly. In other words, when the wind uncertainty increases the ability to down regulate or the ability to curtail wind generation reduces the total cost of system operation.

A 36 unit system with a lost load value of 6000$/MWh is considered for different variations of standard deviation of net demand forecasting error. At 5% of standard deviation (SD) of net demand forecasting error, the total cost of system as per the current system operation is 456221$ while the case considering net demand forecasting error is 39859.4$. At SD of 20%, for the case considering net demand forecasting error the total cost of current system operation is 1585510$ while the case considering net demand forecasting error is 41380.6$. For SD values greater than 20% the case with net demand forecasting error does not decreases the total cost. For SD values higher than 20%, a method is proposed which allows wind curtailment to have optimal system operation. At 55% of SD, the total cost of the system operation with the proposed method is almost reduced by almost 63 times compared to the cost of current system operation case.

Keywords: Wind curtailment, optimal system operation, expected cost of wind forecasting error, reliability cost, regulating power cost

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Nomenclature

Abbreviations

COPT	Capacity on Outage Probability Table
MOC	Maximum On-line Capacity
SD	Standard Deviation
SEK	Swedish krona, currency of Sweden
TSO	Transmission System Operator
UC	Unit Commitment
VOLL	Value of Lost Load

Symbols

Indices

i	index of generating units ranging from 1 to NG
s	index of scenarios ranging from 1 to NS
t	index of time periods ranging from 1 to NT, hours

Functions

$c_i(u_{i,t},p_{i,t})$	production cost of unit i during hour t, \$/h

Parameters

D_t	system demand at time t, MW
D_t^f	forecasted net demand at time t, MW
D_t^a	actual net demand at time t and scenario s, MW
$ECT_{t,s}$	energy curtailment at time t and scenario s, MW
$ENS_{t,s}$	energy not served at time t and scenario s, MW
p_i^{max}	maximum production level of unit i, MW
p_i^{min}	minimum production level of unit i, MW
$\Delta p_{t,s}$	deviation of net demand at time t for scenario s, MW

Continuous Variable

$EENS_t$	expected energy not served at time t, MWh
$LOLP_t$	loss of load probability at time t
$p_{i,t}$	power generated by unit i during time t, MW

Binary variables

$u_{i,t}$	status of unit i at time t

Chapter 1

Introduction

Rapid industrialization and increasing population triggers the rise of global energy demand. The impending energy crisis and soaring oil prices are all converging to the need of alternative energy production. With the swelling carbon foot print by the traditional energy production techniques, there is an immediate need to increase the share of renewable energy. Wind and solar energy are the prime sources that can contribute to the renewable energy share. As renewables are intrinsically dependent on the varying weather conditions, integration of these energy resources into the existing grid is a key challenge. The prognostic growth of wind power capacity in the EU is shown in the Figure 1.1.

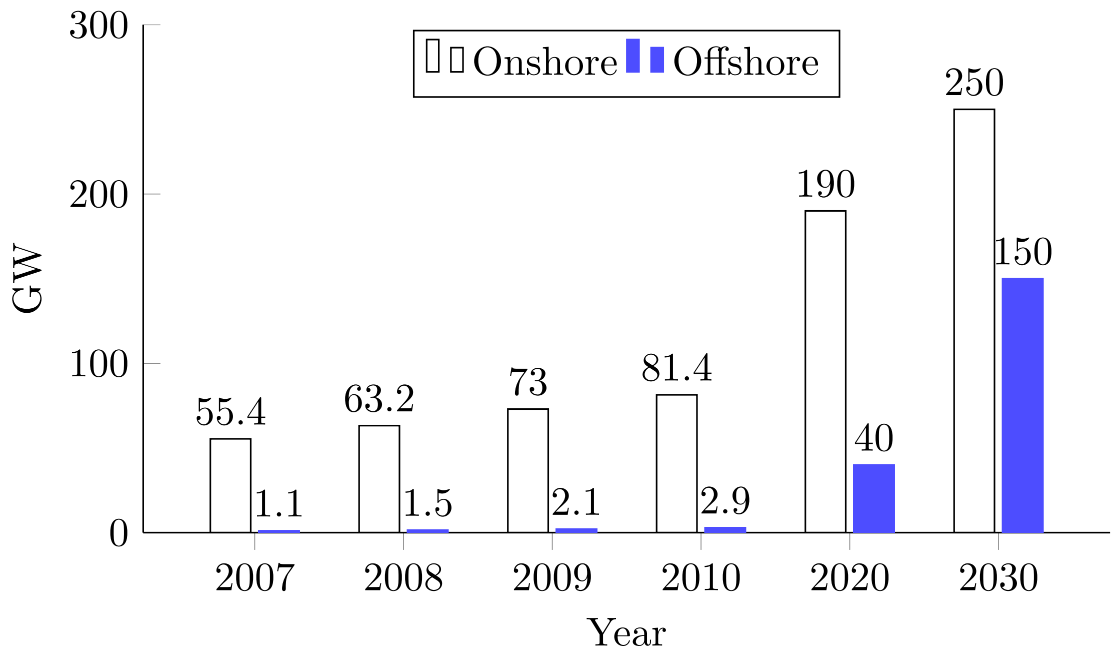

Figure 1.1: Wind power forecast in the EU [1]

The amount of wind power installed worldwide has increased more than sevenfold in the past 10 years from 24 GW in 2001 to almost 197 GW in 2010 [2]. According to the estimates, European union has decided to have at least 20% of its energy to be supplied by renewable sources by 2020. This will increase the renewable share up to 30-35% of the future electricity markets. Renewables are geographically distributed, intermittent and unpredictable which will have extensive effects on power markets, transmission and distribution grids. Due to the above mentioned effects that renewables brings into the existing electrical grid, their integration into the existing system is far more challenging [3].

1.1 Evolution of Nordic Electricity Markets Deregulation

In the beginning of the nineties, the global electric companies have realized that vertical integrated mechanism of electricity trade is inefficient. There are certain setbacks with the then system which include unnecessary investment and lack of competition etc. These circumstances prompted for a radical change in the electricity trade which necessitated to the liberalization of the electricity markets. Market players includes producers, retailers and consumers [4].

In early nineties deregulation of European electricity markets started followed by the integration of national markets of Norway, Sweden, Denmark and Finland. A common power exchange was established and border tariffs were abolished. The prime objective of these reforms were to increase efficiency, to reduce regional prices of electricity for end users and to obtain better balance between power generation capacity and power demand [5].

1.2 Overview of Nord Pool Markets

In 1994 Norwegian gird company Statnett, Swedish grid company Svenska Kraftnät formed a joint electricity trade exchange. Later in 1996 Nord Pool was constituted which became the first power exchange in the world. Finland and Denmark joined Nord Pool in 1998 and 1999 respectively [6]. Nord Pool, the Scandinavian power exchange operates four types of markets: Elspot, Elbas, Eltermin and Eloptions [7].

Elspot is a day ahead market where market players' participate in physical electricity (KWh) trade in the form of bids. This market sets a system (reference) price for electricity on the basis of total quantity of electricity that is traded. The bidding process is closed at 12:00 CET for the next day delivery. A computer algorithm will then decide the system price. The supply bids are placed in the ascending order whereas demand bids are placed in the descending order as shown in the Figure 1.2 and the point of intersection will decide the unconstrained system price. The prices are announced typically between 12:30 to 12:45 CET, which means the trades are settled. The contracts are delivered physically from 00:00 CET [8].

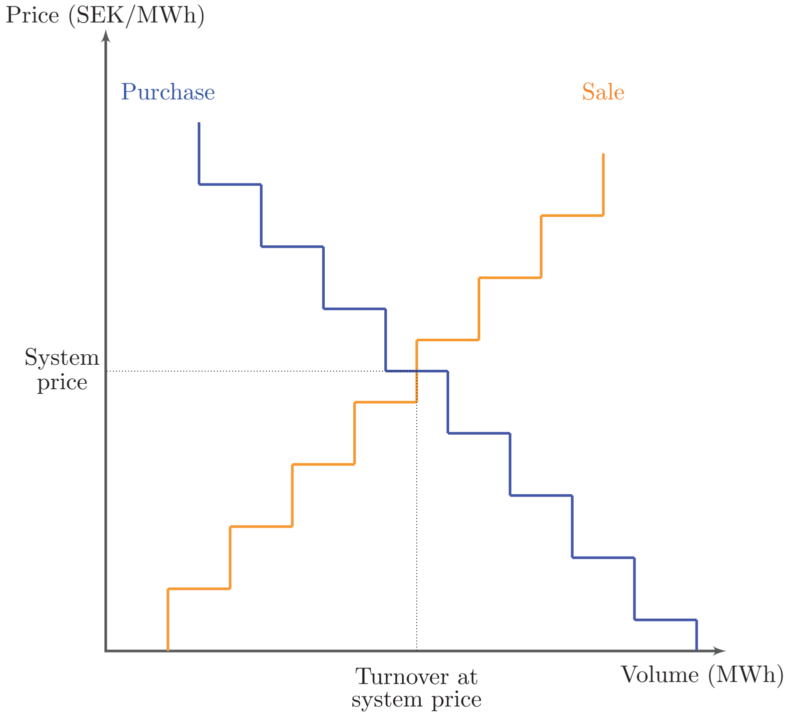

Figure 1.2: Demand and supply curve [8]

Elbas is a balance adjustment intra-day market which covers the period between the end of Elspot market and the delivery hour. It supplements Elspot market and tries to achieve a better balance between demand and supply upon small deviations that may occur due to excess demand or transmission bottlenecks after the day ahead auction is completed. The trade is done on a web based trading system which operates 24/7 and 365 days a year. It increases the transparency of day-ahead and intra day trading prices by reducing the imbalance cost. The contracts are traded until one hour before the delivery hour, usually the liquidity in this market is very low. Elbas will play a major role in the power markets with significant proportion of renewable energy. As renewables are unpredictable by nature and their day-ahead contracts needs to be adjusted based on their produced volumes [8].

Eltermin is a financial market that the traders can trade electricity upto five years ahead to hedge against the fluctuations in the price. It primly consists of future and forward contracts, which allow players to establish a fixed price for future electricity trade. These contracts are only in financial terms unlike Elspot and Elabs where physical electricity is traded [7].

Eloptions is another financial market for risk management and for forecasting future income and costs related to trade in power contracts [7].

Table 1.1 shows the type of the market with respect to the time frame they operate.

Table 1.1: Type of energy market with respect to time frame in Nord Pool

Market or Type of Contract	Time Frame
Bilateral Contracts	Days, weeks, months up to 3 years ahead
Elspot	One Day ahead
Elbas	Up to one hours ahead
Regulating & Balance Service	Real Time

1.3 Role of TSO and Regulating Power Market

Transmission system operator (TSO) is a neutral entity in the power market who facilitates the security of the system by ensuring the balance between demand and supply of electricity. The frequency of the power system must lie within a specific range around 50 Hz ($\pm$0.1 Hz). During a day ahead market, TSO is informed of generation and load schedules for each hour. TSO checks the feasibility of bilateral contracts made by the players to avoid congestion.

In the real time TSO keeps the system power balance by trading electricity between the market players. In regulating the system frequency at the desired set point two cases may arise in regard to the power imbalance [4]. “Up regulation” is the case when consumption exceeds the production, this results in grid frequency falling below 50 Hz. When this happens TSO ensures that one or more producers deliver(s) the deficit. In this case TSO buys more power from producers at a higher rate than the market clearing price(spot market price). It means the TSO is procuring the up regulation. “Down regulation” is the case when production exceeds the consumption, this results in frequency rising above 50 Hz. When this happens TSO ensures that one or more producers reduce(s) the generation. It means the TSO is procuring down regulation. Table 1.2 lists TSOs from different countries in Nord Pool.

TSO accepts the regulation power bids from the market players from 15:00 Hrs on the day before delivery until 45 minutes prior to delivery. Balance responsible parties who can ramp up or ramp down their production level within a given time (15 minutes) usually bid for the regulating power. These bids are placed in the form of stair case in ascending order of marginal price principle (merit-order) and is calculated on an hourly basis in all electricity markets [4].

The regulating power price is determined in accordance with the most expensive bid in the case of upward regulation and the cheapest bid for downward regulation. This process is illustrated in the Figure 1.3. The final regulating power price is applicable for all players who participate in the upward or downward regulation. The power which is used by TSO to regulate the frequency to 50 Hz is called the regulating power. After the real time market TSO makes settlements and levies congestion surcharges and penalty charges.

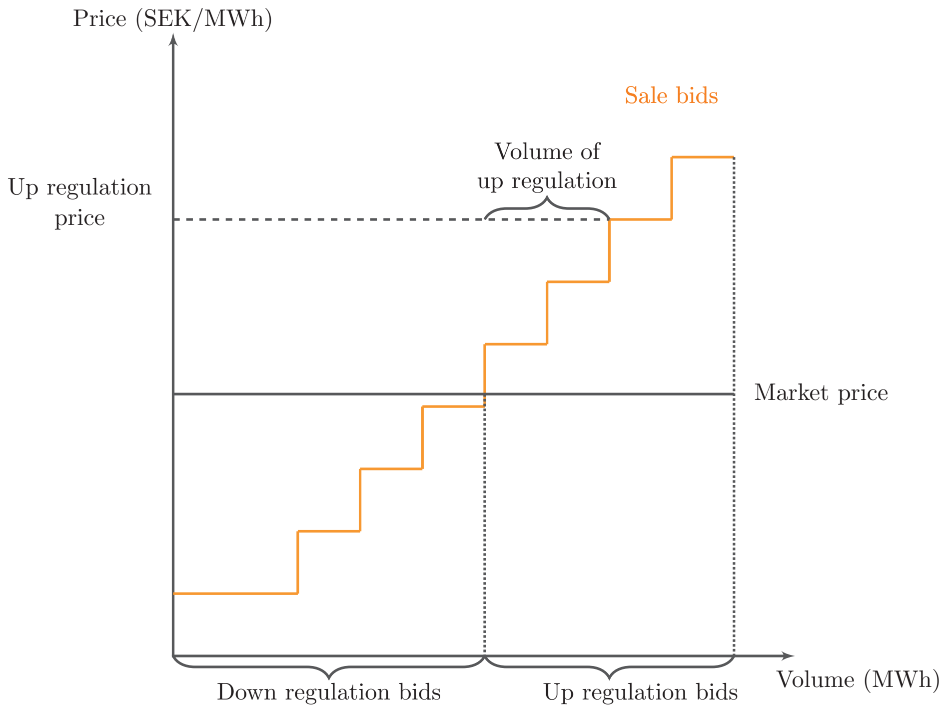

Figure 1.3: Determination of regulating power price [4]

Table 1.2: Nordic countries and their respective TSOs

Country	TSO
Norway	Statnett SF
Sweden	Svenska Kraftnät
Finland	Fingrid
Denmark	Energinet.dk

1.4 Frequency Regulation

The operating reserves are typically characterized depending on the time frame they are prepared to act. Primary reserve is a local automatic control in which governor delivers the appropriate amount of power in response to a frequency change. Secondary reserve is a centralized automatic control which delivers appropriate amount of power in response to a frequency change. Tertiary reserve is a manual control in which change in the dispatch and UC to restore the secondary reserve, to manage eventual congestions, and to bring back the frequency and the interchange programs to their target if the secondary control reserve is not sufficient.

1.5 Impact of Wind Energy on Power System

Wind energy unlike the conventional forms of electricity generation is not demand driven. Power generation from a wind turbine depends on the real time wind speed, which makes it a supply driven production. Furthermore this strong intermittent nature of wind power generation is the prime reason for low capacity factors of wind energy. Variability and unpredictability of wind power should be accounted in integrating with other forms of power generation [2].

The forecast error of wind is proportional to the look-ahead horizon. This will increase short term price volatility in power markets, as the merit order in the following day will less predictable. Additional start-up costs are incurred by this scenario which increases the risk of operation. The ramp-up limits of the generators are also stressed when the wind generation becomes too less at times. TSOs need to procure higher amount of reserves as compared to a similar system without intermittent generation [2]. Wind has a very low marginal cost and based on the day-ahead wind forecast there will be a shift in the market price due to the introduction of wind power.

1.6 Problem formulation

Power systems across the globe has been mainly using a deterministic approach such as the N-1 criterion for the present system operation. The optimal system operation should take into account not only the cost of generation scheduling, but also the cost of system reliability to address the present day stochastic nature of power system aspects. In literature many methods have been proposed to optimize system operation. Author in [9] proposed a method to optimize spinning reserve by using the risk index. This method considers only the operating cost in the objective function and is calculation intensive. Furthermore, the reliability of system is calculated separately. In [10] the optimization is done by considering both running cost and energy not served due to load curtailment in the objective function. The probabilistic nature of outages is not included in the optimization process and the load curtailment from a unit is independent of other unit status. Hence the spinning reserve requirement is overestimated and the optimization solution is suboptimal.

Author in [11] presented a technique to determine the spinning reserve requirement considering error in the wind power and load forecasts. However, the approach used is Monte Carlo simulation, which optimizes system operation for each of the forecasting error scenario. The final spinning reserve is calculated based on the average of the spinning reserve for each of the forecasting error scenario. This is not optimal as the averaged spinning reserve is not optimal with respect to the expected cost of the system operation. In other word, the method does not take into account the expected cost of different forecasting scenarios when optimizing the system operation.

On the other hand, the author in [12] proposed a two stage stochastic programming approach to estimate the spinning reserve considering the expected cost of wind power and load uncertainty. This approach is more optimal than the approach used in [11] as the objective function optimizes the reserve procurement by accounting for the expected cost of wind power and load forecasting error. However, the system analyzed is based on a US market, where there is a day-ahead reserve capacity market. The reserve that can be activated should have committed their capacity in the capacity market. Such a reserve capacity market does not exist in the Nordic electricity market. Therefore, none of above methods can be directly applied to the optimal system operation of the Nordic power system.

1.6.1 Objective

Thus, the aim of this thesis is to formulate a mathematical model that optimizes power system operation following Nordic power market structure by taking into account the expected cost of wind power forecasting error with wind energy curtailment. The cost of the proposed optimal system operation is compared to the current system operation. The economic value of wind energy curtailment is also evaluated.

1.6.2 Tasks

In order to achieve this objective, the work is divided into the following tasks

- Study the related literature on UC based optimal system operation that considers generator outages and wind and load forecasting error.
- Propose and implement a suitable optimization model with respect to Nordic power market structure that takes into account the wind power forecasting error by using two-stage stochastic programming method.
- Evaluate the economic value for wind energy curtailment based on the optimization model proposed above.
- Test the algorithm with a 36-unit system.

1.7 Structure of Thesis

- Chapter 1 provides the background regarding the deregulation of power sector in Nordic countries and evolution of single largest Nordic power market. Impacts of growth in intermittent generations into the grid is analysed. It also introduces the objective of the thesis and problem description.
- Chapter 2 provides a literature review of power system operation with corresponding optimization models.
- Chapter 3 provides the proposed mathematical model for optimal system operation considering wind forecasting error. The economic/social benefits of incorporating wind curtailment in handling wind forecasting error is presented in detail. The proposed algorithm is tested initially with 3-unit system and later with a 36-unit system.
- In Chapter 4, conclusions and future work of this thesis are presented.

1.8 Contributions of this Thesis

The main contribution of the the method to evaluate is that the economic value of wind energy curtailment using the UC model based on two-stage stochastic programming for optimal system operation.

Chapter 2

Review of UC Models for Optimal System Operation

2.1 Traditional UC Formulation

Unit commitment is a formulation that determines which unit or a set of units are to be committed to satisfy the forecasted load. The word commit simply means "to commit" or to turn ON a generating unit. As it is not economical to run too many generating units for a particular load, a decision should be made based on the objective function (minimize cost, minimize emissions, maximize profit). The principal UC problem is formulated as [13]:

$$min\ C = \sum_{t=1}^{NT}[\sum_{i=1}^{NG}[c_i(u_{i,t},p_{i,t})]] \tag{2.1}$$

where:
$c_i(u_{i,t},p_{i,t})$ is power production cost of unit i during period t.
$p_{i,t}$ is the power produced by unit i during period t.
$u_{i,t}$ is the status of unit i during period t, (1:ON, 0:OFF).
NT is the number of periods in the optimization horizon.
NG is the number of available generating units.

2.1.1 Basic Constraints

- The power generation limits of generating unit i during time period t is given by the inequality constraints as expressed by:

  $$u_{i,t} \times p_i^{min} \leq p_{i,t} \leq u_{i,t} \times p_i^{max} \tag{2.2}$$

  These limits pertains to the thermal properties of boiler operation in a thermal or nuclear power plants. The minimum power production limits are due to the fuel combustion stability and inherent steam generator design constraints [13].

- The total power generation in a system should be equal to the system load at any given time t. The power balance constraint is mathematically expressed by:

$$\sum_{i=1}^{NG} p_{i,t} = D_t \tag{2.3}$$

2.2 UC Considering Load and Wind Forecasting Error

2.2.1 Load Forecasting Error

Load forecast errors can yield sub-optimal UC decisions. It has always been vital for the planning and operation decisions in the power system. Especially in deregulated electricity markets where the electricity is more viewed as a commodity, the time varying supply and demand together with the load forecasting error make the decision making more complicated [14]. Figure 2.1 represents the actual load and forecasted load on 2012-10-10 in Sweden.

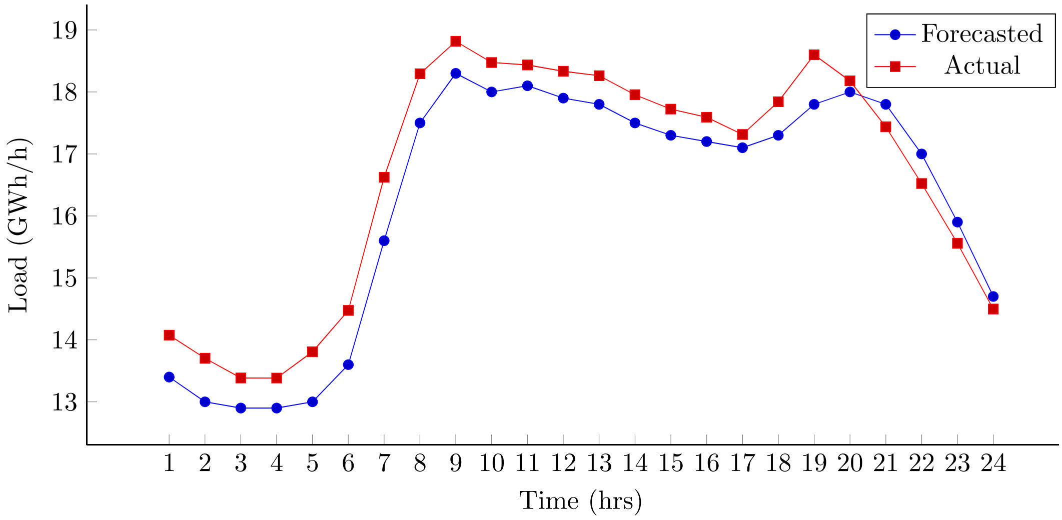

Figure 2.1: Day ahead load and actual load in Sweden on 2012-10-10 [15]

To improve the reliability and efficiency of the power system generation it is critically important to know the load forecasting error and its consequences. Like any forecast, load forecast has errors associated with it and cannot be predicted exactly. Load forecast error depends upon multiple factors including temperature and humidity and is usually proportional to the amount of load at any given hour. There is a critical necessity to consider the effect of load forecast error on the generator scheduling in order to minimize the additional cost it causes [16].

2.2.2 Wind Forecasting Error

Unlike traditional generators, wind power is stochastic in nature; therefore its integration into power system affects power system operation. As wind and load uncertainty coexist, their corresponding effect on modern power system can be analysed in a better way by analysing their combined effects. This can be done by considering wind as a negative load. This means that the uncertainty associated with wind will increase the uncertainty in net demand. Actual Wind and forecasted wind in DK1 on 2012-10-10 is shown in the Figure 2.2.

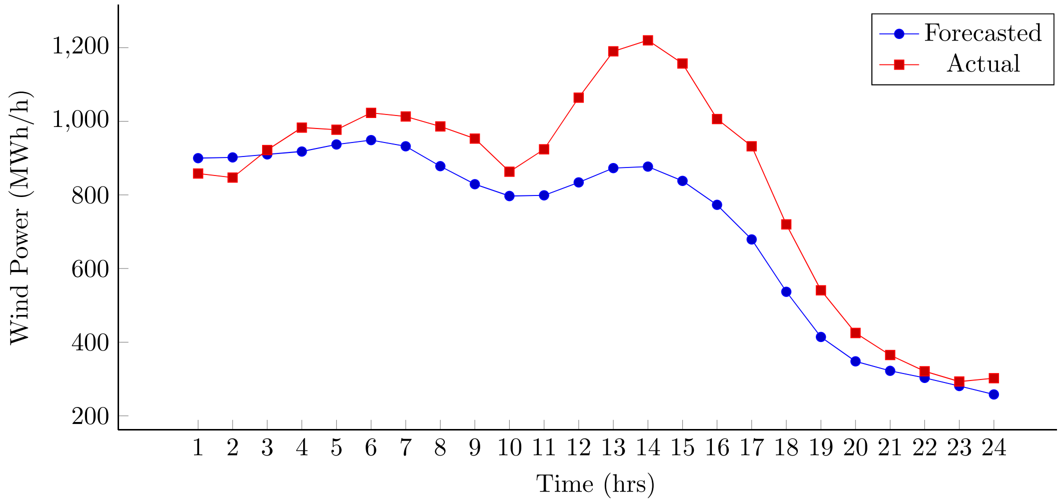

Figure 2.2: Forecasted wind and actual wind in DK1 on 2012-10-10 [15]

The net demand can be defined as:

$$ND = D - W \tag{2.4}$$

where ND is the net demand which contains both wind W and load D.

The error in wind can be defined as:

$$\Delta W = W^a - W^f \tag{2.5}$$

where ΔW is the error associated with wind forecast, W^a is the actual wind and W^f is the forecasted wind.

The error in load could be defined as

$$\Delta D = D^a - D^f \tag{2.6}$$

Total error is defined as:

$$\Delta p = \Delta D - \Delta W \tag{2.7}$$

From (2.5)-(2.7) it can be observed that total deviation increases with increase in uncertainty of either load or wind.

2.2.3 Costs Incurred due to Forecasting Errors

Two cases may arise in net demand forecasting: under forecasting and over forecasting. Under-forecasting conduces insufficient MOC. MOC, which is required to handle N-1 contingency is used to compensate the forecasting mismatch. This could also leads to purchase of expensive power during the real time.

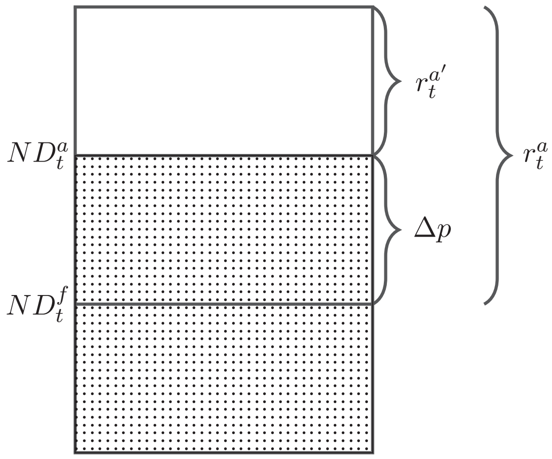

Figure 2.3: Under forecasting of net demand

Figure 2.3 shows the implications of under forecasting error on power system. For the day ahead net demand forecast (ND_t^f), the available MOC is r_t^a. When the actual net demand is higher than the forecasted net demand then, a part of MOC is allocated for up-regulation. The new available MOC after up-regulation is represented as $r_t^{a'}$. This could also expose the system to decreased reliability, which will result in increased socio-economic cost. An improved net demand forecast implies that the actual net demand (ND_t^a) is closer to the day ahead net demand forecast (ND_t^f) which lead to smaller deviation (Δp).

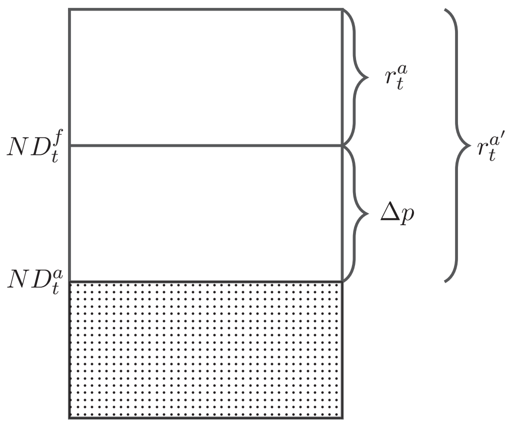

Figure 2.4: Over forecasting of net demand

Figure 2.4 shows the implications of over forecasting error on power system. The day ahead maximum available MOC is r_t^a, which is greater than the required MOC $r_t^{a'}$ after the down regulation to meet the actual net demand forecast (ND_t^f). In this way, over forecasting of net demand (ND_t^f) results in committing of extra generation, unnecessary start-up of generators and excess MOC. Thus, these inaccuracies in net demand forecasting could hamper the overall economic efficiency.

2.2.4 Regulating Power

In order to negate the effects of net demand forecast error and to ensure the system power balance, TSO in real time procures regulating power to balance the consumption and production. The maximum available MOC (r_t^a) with the day ahead scheduling is used to balance the net demand increment due to error. This increment in generation to compensate the actual net demand (ND_t^a) is called the regulating power (p^{reg}). At times when actual net demand is less than the forecasted net demand (in the case of over forecasting), TSO down regulate the generation to compensate for the actual net demand (ND_t^a). In this case the regulating power (p^{reg}) becomes negative. The concept of regulating power (p^{reg}) is explained in the following sections and can be expressed as:

$$p_{t,s}^{reg} = ND_{t,s}^a - ND_t^f,\ ifENS_{t,s} = 0 \tag{2.8}$$

$p_{t,s}^{reg}$ is the regulating power during time t and scenario s, which is the difference between actual net demand(ND_t^a) and day ahead net demand forecast (ND_t^f). $ENS_{t,s}$ is the energy not served due to the error in forecasting net demand during hour t and scenario s.

Up Regulation

Forecasted net demand at hour 1, $ND_1^f = 80MW$.
Actual net demand at hour 1, $ND_1^a = 88MW$.
p_1^{reg}=88MW-80MW=8MW.

Table 2.1: Regulating power for under forecasted net demand

Day ahead scheduling ($ND^f = 80$MW)					Real time scheduling ($ND^a = 88$MW)		
	Unit-1	Unit-2	Unit-3		Unit-1	Unit-2	Unit-3
UC	1	0	1		1	0	1
p	25	0	55		25	0	55
p^{reg}	0	0	0		8	0	0

From Table 2.1 it is evident that the regulating power is positive in this case as forecasted net demand is less than the actual net demand and the generating unit with low incremental cost will be contributing for the regulating power irrespective of VOLL. The regulating power however does not have any effect on the day ahead generator scheduling, but in the real time it is decided by the system imbalance.

Down Regulation

Table 2.2: Regulating power for over forecasted net demand

Day ahead scheduling ($ND^f = 80$MW)					Real time scheduling ($ND^a = 72$MW)		
	Unit-1	Unit-2	Unit-3		Unit-1	Unit-2	Unit-3
UC	1	0	1		1	0	1
p	25	0	55		25	0	55
p^{reg}	0	0	0		0	0	-8

From Table 2.2 it can be inferred that during over forecasting net demand conditions the regulating power is negative. This means that the power scheduling during real time should be compensated by some means, which is done by the generator (Unit-3). As Unit-1 is already operating at its lower power limit (p^{min}) the regulating power is provided by Unit-3.

2.2.5 UC Considering Load and Wind Forecasting Error

Author in reference [12] proposed a two stage stochastic programming to compute the optimal reserve requirements. The first stage reflects the reserve capacity and day-ahead spot market whereas the second stage includes the stochastic nature of the wind generation. However, the author considered a day ahead capacity reserve market which is not the case with the Swedish electricity markets.

In the next chapter, the stochastic programming method proposed in reference [12] is applied, excluding the reserve capacity market to reflect the Swedish market decision process.

2.2.6 Two stage stochastic programming

A two stage stochastic programming is a method of optimization when dealing with uncertainties. It involves two stages of formulation, a first stage formulation with deterministic variables and the second stage formulation that includes stochastic/probabilistic variables. In the second stage, the stochastic variables are modelled according to a certain probability distribution and the first stage decision making tries to find a solution that satisfies all the scenarios [17].

The two stage stochastic programming can be applied to a UC problem that involves load and wind forecasting uncertainties as follows [12]

$$min\ \mathrm{C} = c_i(p_i) + \mathrm{E}(\mathrm{X}_s) \tag{2.9}$$

$\mathrm{E}(\mathrm{X}_s)$ represents the expectation of cost due to uncertainties in the second stage. X_s represents the cost that occur at the second stage decision making that includes the following

- Cost of regulating power
- Cost of lost load
- Cost of curtailed generation

In this thesis the curtailed generation cost is not considered and is set to zero. The detailed formulation of the two stage stochastic programming to solve the UC problem with load and wind forecasting errors is discussed in the next chapter.

Chapter 3

Proposed UC Model for Optimal System Operation of Power System

3.1 Optimal System Operation Considering the Expected Cost of Forecasting Error with Wind Curtailment

3.1.1 Mathematical Formulation

The proposed objective function consists of three parts. The first part of the objective function represents the first stage decision making which includes the operating cost. The second and third part represent the second stage decision making which includes the regulating power cost and reliability cost due to net demand forecasting error.

The objective of the system operation is to

$$min\ C = \sum_{t=1}^{NT}[\sum_{i=1}^{NG}[c_i(u_{i,t}, p_{i,t}) + \frac{1}{NS} \times \sum_{s=1}^{NS}[c_i(p_{i,t,s}^{reg}) + VOLL \times ENS_{t,s}^{f}]]] \tag{3.1}$$

The above objective function is subjected to the following constraints

- Day ahead power balance

$$\sum_{i=1}^{NG} p_{i,t} = ND_t^f \tag{3.2}$$

- Generation limits

$$u_{i,t} \times p_i^{min} \leq p_i + p_i^{reg} \leq u_{i,t} \times p_i^{max} \tag{3.3}$$

- ENS calculation

$$ENS_{t,s}^{f} = \Delta p_{t,s} - p_{t,s}^{reg},\ if\ \Delta p_{t,s} > 0 \tag{3.4}$$

$$ENS^{f}_{t,s} = 0,\ if\ \Delta p_{t,s} \leq 0 \tag{3.5}$$

Energy curtailed may refer to energy that is wasted or burned. A portion of wind is curtailed/reduced from the system, thereby increasing the on-line conventional power capacities. At the moment of wind curtailment, the conventional ON generators will produce to their minimum power production limits if ramp rate are not the limiting factor. The formulation governing the energy curtailment is given as follows:

$$ECT_{t,s} = p^{reg}_{t,s} - \Delta p_{t,s},\ if\ \Delta p_{t,s} \leq 0 \tag{3.6}$$

$$ECT_{t,s} = 0,\ if\ \Delta p_{t,s} \geq 0 \tag{3.7}$$

3.2 Case Study

3.2.1 Description of the System

3 Unit System

The three unit test system is derived from the 36 unit system from reference [18]. Thermal units 22,23,24 are considered with altered generation limits while their cost characteristics are unchanged. The total generation capacity of the altered system is 600 MW and cumulative sum of generator minimum limits is 150 MW. The 3 unit system is shown below

$$c_1(p_1) = 0.00259 \times p_1 + 23 \times p_1^2 + 259.131,\ \ 50 \leq p_1 \leq 200 \tag{3.8}$$

$$c_2(p_2) = 0.0026 \times p_2 + 23.1 \times p_2^2 + 259.649,\ \ 50 \leq p_2 \leq 200 \tag{3.9}$$

$$c_3(p_3) = 0.00263 \times p_3 + 23.2 \times p_3^2 + 260.176,\ \ 50 \leq p_3 \leq 200 \tag{3.10}$$

36-Unit System

The data of the 36-unit system is taken from [18]. The total generation capacity of the system is 6183 MW and cumulative sum of generator minimum limits is 1898 MW. The data for 36 unit system is given in Appendix A.1.

3.2.2 Input Data

3-Unit System

For the 3-unit system the net demand scenarios are directly generated without considering wind and load individually. A forecasted net demand of 325 MW is assumed. The net demand scenarios are generated based on the following

$$ND = ND^f + \mathcal{N}(0,\sigma) \tag{3.11}$$

where $\mathcal{N}$ is normal distribution of net demand scenarios. The generated net demand scenarios are given in Figure 3.1. The net demand scenarios ranges from 106.21 MW and 563.93 MW.

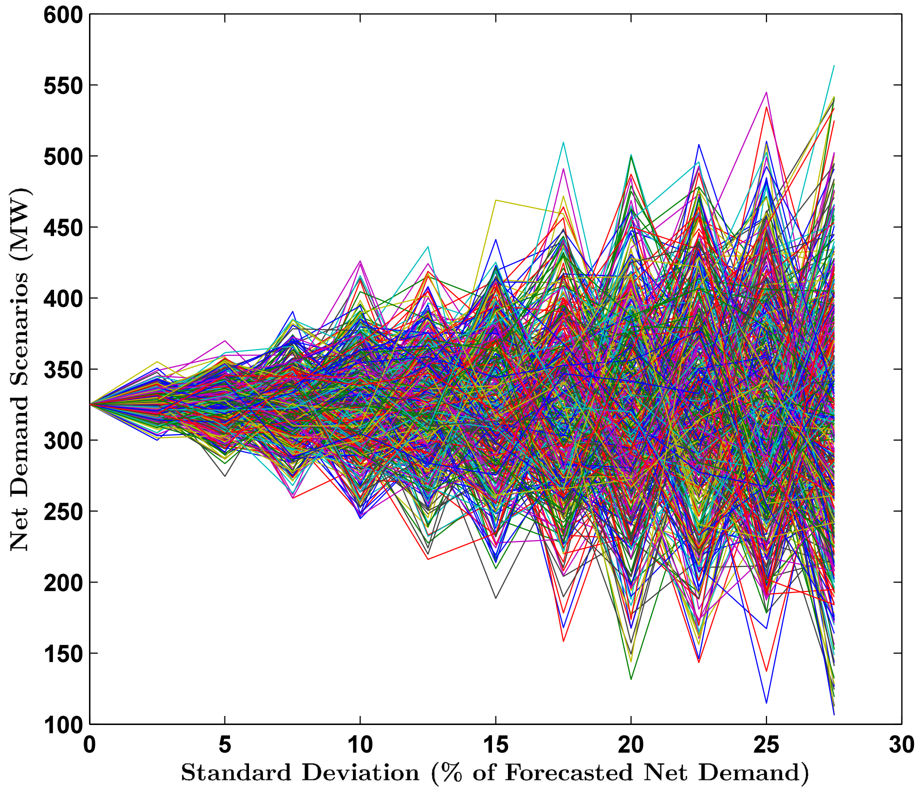

Figure 3.1: Generated net demand scenarios

36-Unit System

The Net demand scenarios for the 36-unit system are generated as given in (3.12) - (3.17)

Forecasted demand is given as:

$$D^f = 4690 \text{ MW} \tag{3.12}$$

Forecasted wind, Maximum installed wind capacity are given as:

$$W^f = 1000 \text{ MW},\ W^{max} = 3000 \text{ MW} \tag{3.13}$$

Forecasted net demand is therefore:

$$ND^f = D^f - W^f = 3690 \text{ MW} \tag{3.14}$$

Standard deviation of wind forecasting error is given by:

$$\sigma = \frac{\chi}{100} \times W^{max} \tag{3.15}$$

Wind scenarios are generated as:

$$W = W^f + \mathcal{N}(0,\sigma) \tag{3.16}$$

where $\mathcal{N}$ is normal distribution of wind scenarios. Neglect the demand forecasting error, i.e. $D = D^f$. The net demand scenarios are

$$ND = D - W \tag{3.17}$$

Figure 3.2 shows the generated 1000 wind scenarios. Initially wind scenarios are generated for a forecasted wind (W^f = 1000 MW) as shown in the upper figure. These scenarios varies between -3727.9 and 6197.8 MW. While the total installed wind capacity is 4000 MW, the higher scenarios should be confined to the total installed wind capacity. All the negative wind scenarios are truncated at 0 MW as they do not exists in real time. The resulting wind scenarios lie between 0 MW and 4000 MW (W^{max}) and are shown in the lower figure.

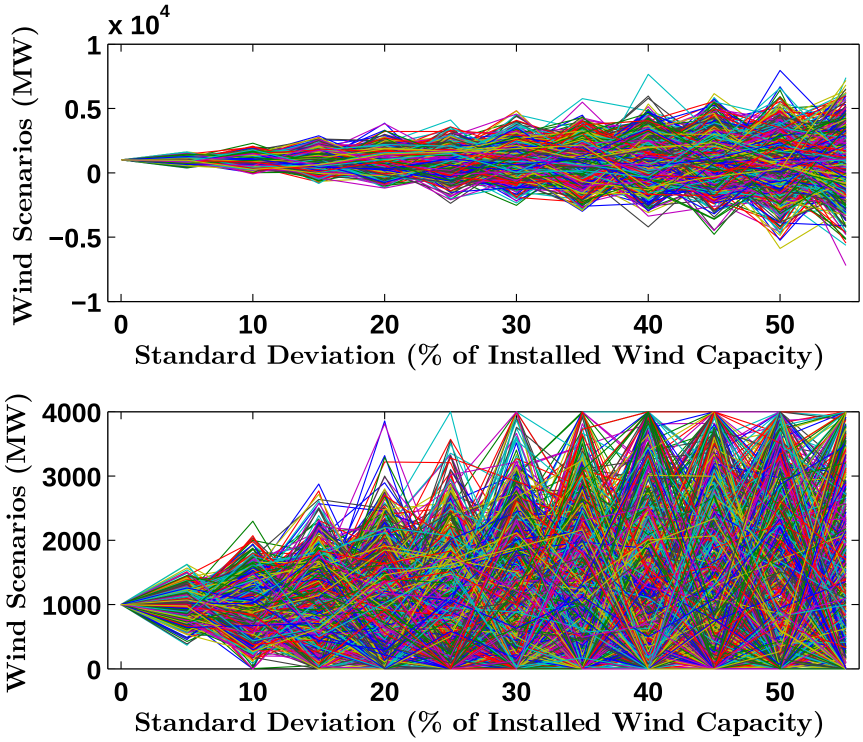

Figure 3.2: Generated wind scenarios

According to (3.17) wind scenarios are converted to net demand scenarios. Figure 3.3 shows the generated net demand scenarios, which range from 690 MW to 4690 MW.

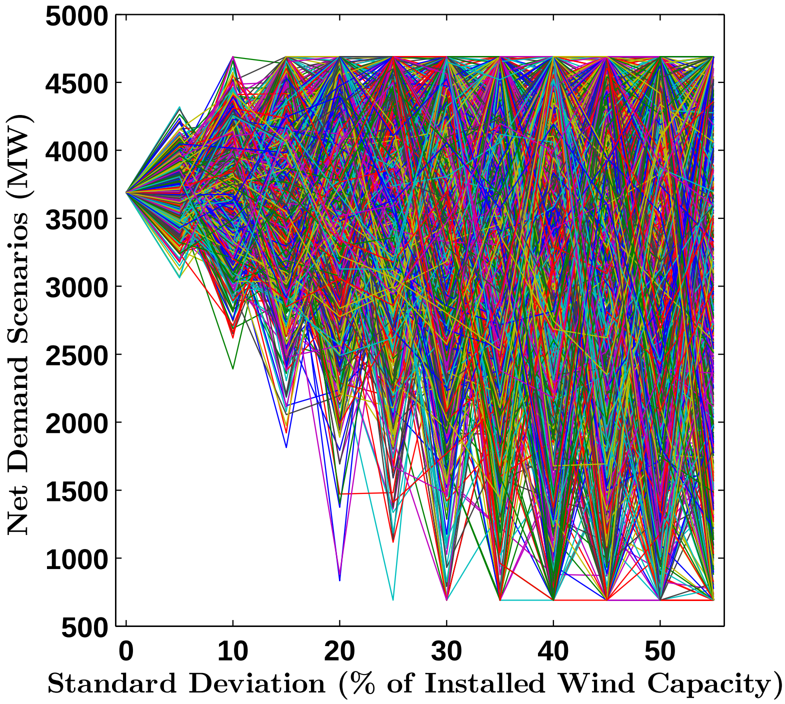

Figure 3.3: Generated net demand scenarios

3.2.3 Results and Discussion

3-Unit System

Figure 3.4 shows various costs with increasing forecasting error with a VOLL of 1000 \$/MWh employing wind energy curtailment. Compared to the case without ECT, the total cost until 10% of SD is the same. This is because all the net demand scenarios are within the MOC. At 12.5% of SD, the case without wind curtailment records a minimal unserved energy. This unversed energy is compensated by turning on a unit-3 in this case.

Until 17.5% of SD, regulating power from the ON generators will compensate the higher net demand scenarios. From 20% of SD, ECT compensates the probability of lower net demand scenarios thereby allowing unit-3 to be in ON state. Keeping unit-3 ON, all the higher net demand scenarios are compensated with the MOC. Thereby making zero unserved energy which in-turn decreases total cost compared to the case without ECT. Energy curtailed here does not have any influence on the cost function.

When ECT is included in the optimization process, a new unit will commit for higher actual net demand scenarios and the overall cost will reduce as ENS decreases. On the other hand if ECT is not allowed, the new unit will not commit which increases ENS and lead to an increase in the total cost. The total cost comparison for both cases is shown in the Table 3.1.

Table 3.1: Total cost in $ with and without ECT

SD (%)	Total Cost without ECT	Total Cost with ECT	Reduced Cost with ECT
20	12046	8356	30.63%
22.5	13996	8439	39.70%
25	15421	8479	45.01%
27.5	15937	8339	47.67%

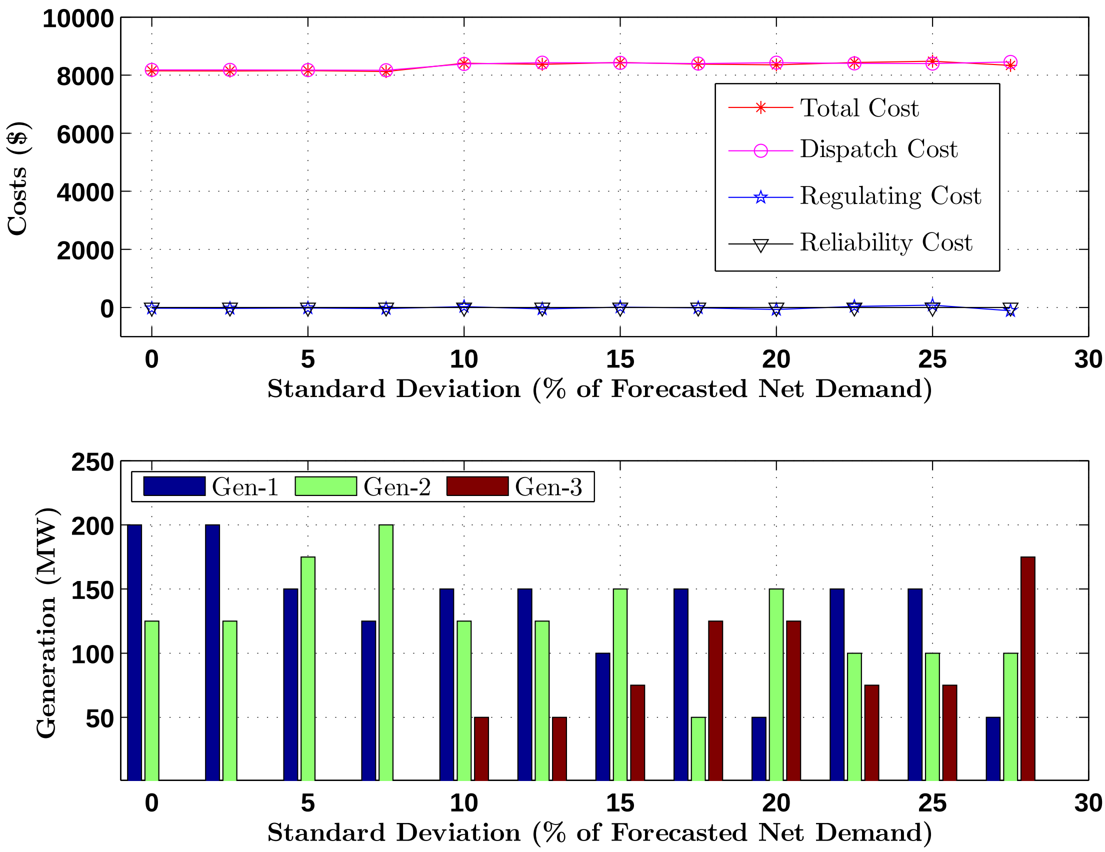

Figure 3.4: Different costs with varying SD with ECT, for a VOLL of 1000 $/MWh

36-Unit System

Figure 3.5 shows UC, different costs with increasing SD of net demand forecasting error when energy curtailment is allowed. The total cost is almost the same as the case without wind curtailment until SD of 20%, this is because the net demand scenarios do not vary much with respect to the mean value (3690 MW). Once the scenarios crosses 20%, there will be net demand scenarios which are lower than cumulative minimum generation limits where the need of energy curtailment occurs. This helps to fill the gap between cumulative minimum generation limits and lower actual net demand scenarios. As the lower scenarios are fulfilled the higher net demand scenarios are compensated by the regulating power. This will lead to reduced unserved energy, which in turn reduces the total cost.

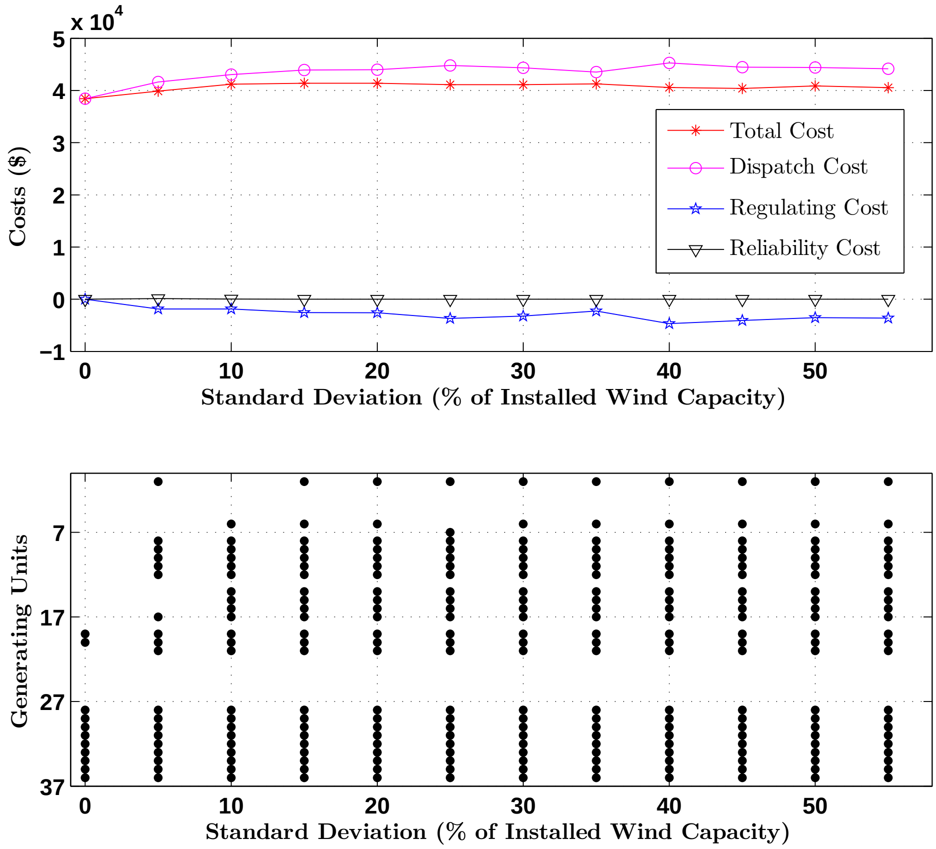

Figure 3.5: Different costs with varying SD with ECT for VOLL of 6000 $/MWh

3.3 Current System Operation Principle

In the current system operation, the spot market clearing does not consider the stochastic nature of load and wind in the day ahead generator scheduling. This is a deterministic approach as it does not take into account the expected costs of regulating power due to the forecasting error of system load and wind. During the real-time operation, the regulating power needs either to up regulate or down regulate to compensate the actual net demand (load+wind) of the system. The net demand forecasting error is modelled as a normal distribution.

3.3.1 Mathematical Formulation

Representing the spot market clearing as a UC formulation, the objective function is to minimize the total generation cost [19]

$$min\ C = \sum_{t=1}^{NT}[\sum_{i=1}^{NG}[c_i(u_{i,t}, p_{i,t})]] \tag{3.18}$$

The above objective function is subject to the following constraints [19]

1. Power balance, $\forall\ t$

$$\sum_{i=1}^{NG} p_{i,t} = ND_t^f \tag{3.19}$$

2. Generation limits, $\forall\ i$,t

$$u_{i,t} \times p_i^{min} \leq p_i \leq u_{i,t} \times p_i^{max} \tag{3.20}$$

As a result, the generator units ON/OFF status and power generation in spot market can be determined. However, the actual system net demand may deviate from the forecasted value cleared in the spot market. This leads to the following forecasting error of net demand

$$\Delta p_{t,s} = ND_{t,s}^a - ND_t^f \tag{3.21}$$

As a result, TSO needs to activate regulating power depending on the direction of the forecasting error:

$$p_{t,s}^{reg} = min\{\Delta p_{t,s}, u_{i,t} \times p_i^{max} - p_{i,t}\},\ if \Delta p_{t,s} > 0 \tag{3.22}$$

$$p_{t,s}^{reg} = max\{\Delta p_{t,s}, u_{i,t} \times p_i^{min} - p_{i,t}\},\ if \Delta p_{t,s} < 0 \tag{3.23}$$

$$p_{t,s}^{reg} = 0,\ if \Delta p_{t,s} = 0 \tag{3.24}$$

The corresponding system EENS is

$$ENS_{t,s}^{f} = \Delta p_{t,s} - p_{t,s}^{reg},\ if \Delta p_{t,s} > 0 \quad (3.25)$$

$$ENS_{t,s}^{f} = 0,\ if \Delta p_{t,s} \leq 0 \quad (3.26)$$

$$EENS_{t}^{f} = \frac{1}{NS} \times \sum_{s=1}^{NS} ENS_{t,s}^{f} \quad (3.27)$$

The resulting reliability cost due to EENS can be expressed as

$$VOLL \times EENS_{t}^{f} \quad (3.28)$$

Consequently, the total cost can be calculated by

$$C + c(p^{reg}) + EENS_{t}^{f} \times VOLL \quad (3.29)$$

Ramp rate, minimum up time and minimum down time constraints are not considered in this analysis to understand the clear effect of stochastic nature of wind power on system operation. Therefore the simulations are done considering hours independently not as a continuous time horizon.

3.3.2 Simulation Results

3-Unit System

Figure 3.6 shows different costs characteristics with increasing forecasting error for a forecasted net demand of 325 MW and a VOLL of 1000 $/MWh. The UC is the same for increasing forecasting error as it does not account for the cost of forecasting error of system net demand. With increasing forecasting error ENS is increasing which causes the total cost to increase. This is due to the fact that increasing SD will widen the actual net demand scenarios and also violates the minimum and maximum generation limits of the generating units. Violating the maximum generation limits will cause the ENS as the maximum on-line capacity cannot compensate this deviation. On the other hand violating lower limits leads to wind energy curtailment. The other drawback of this approach is that it cannot commit new unit for an increasing value of VOLL.

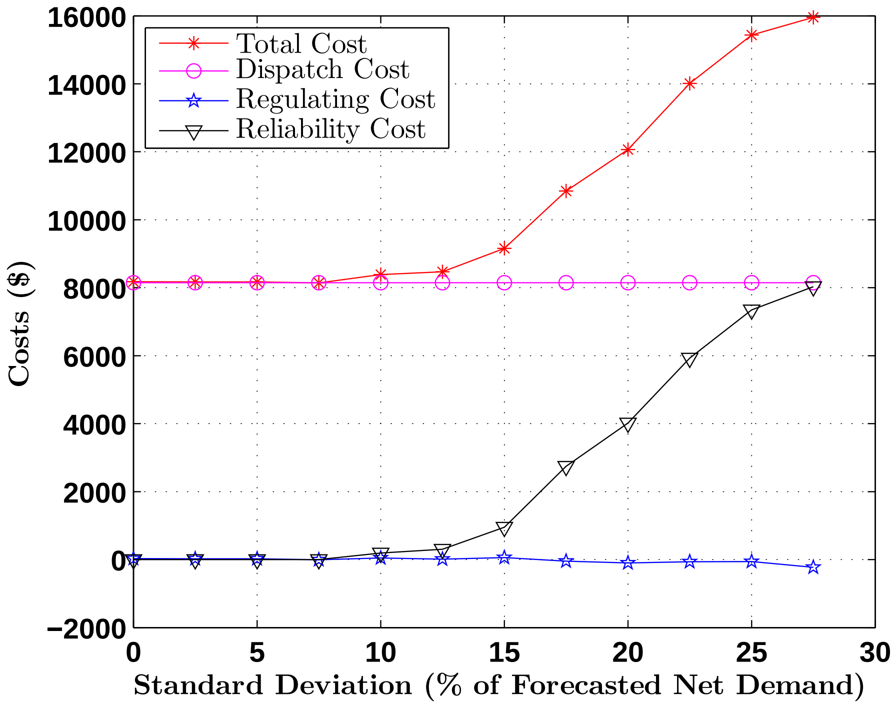

Figure 3.6: Different costs with increasing SD, for a VOLL of 1000 $/MWh

The impact of actual net demand scenarios on the regulating power and ENS can be explained as follows:

- Net demand scenarios which are lower than the forecasted net demand: In this case the total deviation ($\Delta p_{t,s}$) will be negative, which means the ON generators need to down regulate to meet the actual net demand.

$$\Delta p_{t,s} = -p_{t,s}^{reg} \tag{3.30}$$

- Net demand scenarios which are higher than the forecasted net demand and within the total generation limit: In this case total deviation ($\Delta p_{t,s}$) will be positive, which means the ON generators need to up regulate to meet the actual net demand.

$$\Delta p_{t,s} = p_{t,s}^{reg} \tag{3.31}$$

- Net demand scenarios which are higher than the forecasted net demand and exceeding the total generation limit: In this case there will be a portion of total deviation ($\Delta p_{t,s}$) that cannot be compensated by the total generation limit which is termed as ENS.

$$\Delta p_{t,s} = p_{t,s}^{reg} + ENS_{t,s}^{f} \tag{3.32}$$

- Net demand scenarios which are lower than the forecasted net demand and less than the cumulative minimum on-line generation limits: In this case the total deviation ($\Delta p_{t,s}$) will be negative, which means there will be a portion of curtailed energy in addition to the down regulation.

$$\Delta p_{t,s} = p_{t,s}^{reg} - ECT_{t,s}^{f} \tag{3.33}$$

36-Unit System

Figure 3.7 shows UC, different costs with increasing SD of the net demand forecasting error. Even though the day ahead spot market clearing does not consider the expected cost of net demand forecasting error in this case, regulating power market clears the irregularities of the net demand originating from stochastic wind and load forecasting errors. Over different SDs of wind forecasting error, the dispatch cost remains to be the same as the generator schedule is only based on the forecasted net demand. Also the objective function is to minimize the dispatch cost only. The cumulative maximum capacity of ON generators is 2700 MW, when the net demand scenarios exceed this value they lead to unserved energy. This increased cost is addressed in the next section where the spot market clearing considers the expected cost due to wind forecasting error. Number of scenarios generated are set to 1000.

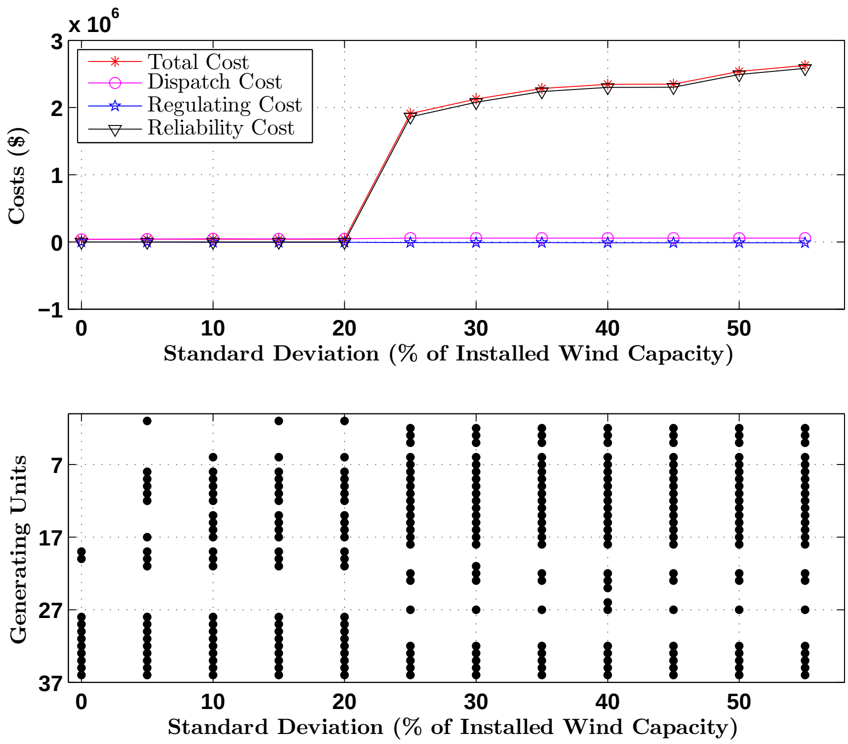

Figure 3.7: Different costs with increasing SD, for a VOLL of 6000 $/MWh

3.4 Optimal System Operation Considering the Expected Cost of Forecasting Error Without Wind Curtailment

To account for the cost of the net demand forecasting error on the system operation, the stochastic nature of the net demand is considered in the day ahead scheduling. In other words, spot market clearing in this case considers the expected costs of net demand forecasting error within the UC decision making to optimize the total cost of the system.

3.4.1 Mathematical Formulation

The objective of the system operation is to

$$min\ C = \sum_{t=1}^{NT}[\sum_{i=1}^{NG}[c_i(u_{i,t}, p_{i,t}) + \frac{1}{NS} \times \sum_{s=1}^{NS}[c_i(p_{i,t,s}^{reg}) + VOLL \times ENS_{t,s}^{f}]]] \tag{3.34}$$

The proposed objective function above consists of three parts. The first part of the objective function represents the first stage decision making which includes the operating cost. The second and third part represent the second stage decision making which includes the regulating power cost and reliability cost due to net demand forecasting error. The above objective function is subjected to the following constraints

- Day ahead power balance

$$\sum_{i=1}^{NG} p_{i,t} = ND_t^f \tag{3.35}$$

- Generation limits

$$u_{i,t} \times p_i^{min} \leq p_i + p_i^{reg} \leq u_{i,t} \times p_i^{max} \tag{3.36}$$

- ENS calculation

$$ENS_{t,s}^f = \Delta p_{t,s} - p_{t,s}^{reg},\ if\ \Delta p_{t,s} > 0 \tag{3.37}$$

$$ENS_{t,s}^f = 0,\ if\ \Delta p_{t,s} \leq 0 \tag{3.38}$$

The formulation of regulating power constraint is given in (3.39). This constraint is responsible for the allocation of regulating power among generators. This equation will shut down the generators when the actual net demand is much less than the forecasted net demand. The left hand-side of the equation represents the down regulating reserve for the forecasted load which is similar to MOC. The system cannot down regulate more than the allowed amount (RHS value). This means that the wind in the system should be curtailed in order to satisfy the lower net demand scenarios. This constraint allows more generators to turn ON for the same forecasted net demand. This makes the small units ON rather than committing large units.

$$p_i^{min} * u_{i,t} - p_{i,t} \leq \Delta p_{t,s},\ if \Delta p_{t,s} < 0 \tag{3.39}$$

$$p_{t,s}^{reg} = max\{\Delta p_{t,s}, u_{i,t} \times p_i^{min} - p_{i,t}\},\ if \Delta p_{t,s} < 0 \tag{3.40}$$

$$p_{t,s}^{reg} = min\{\Delta p_{t,s}, u_{i,t} \times p_i^{max} - p_{i,t}\},\ if \Delta p_{t,s} > 0 \tag{3.41}$$

The flow chart shown in the Figure 3.8 represents the methodology of the proposed model. This two-stage stochastic programming formulation is similar to the one proposed in reference [12]. However, in reference [12] the objective is to find the day-ahead reserve capacity whereas in this formulation, the day-ahead reserve capacity is not the purpose. Instead, the formulation represents the optimal system operation cost when market clearing considers the expected cost of forecasting error. In addition, there is no such reserve capacity market in Sweden as the one described in reference [12], which is based on the US market structure.

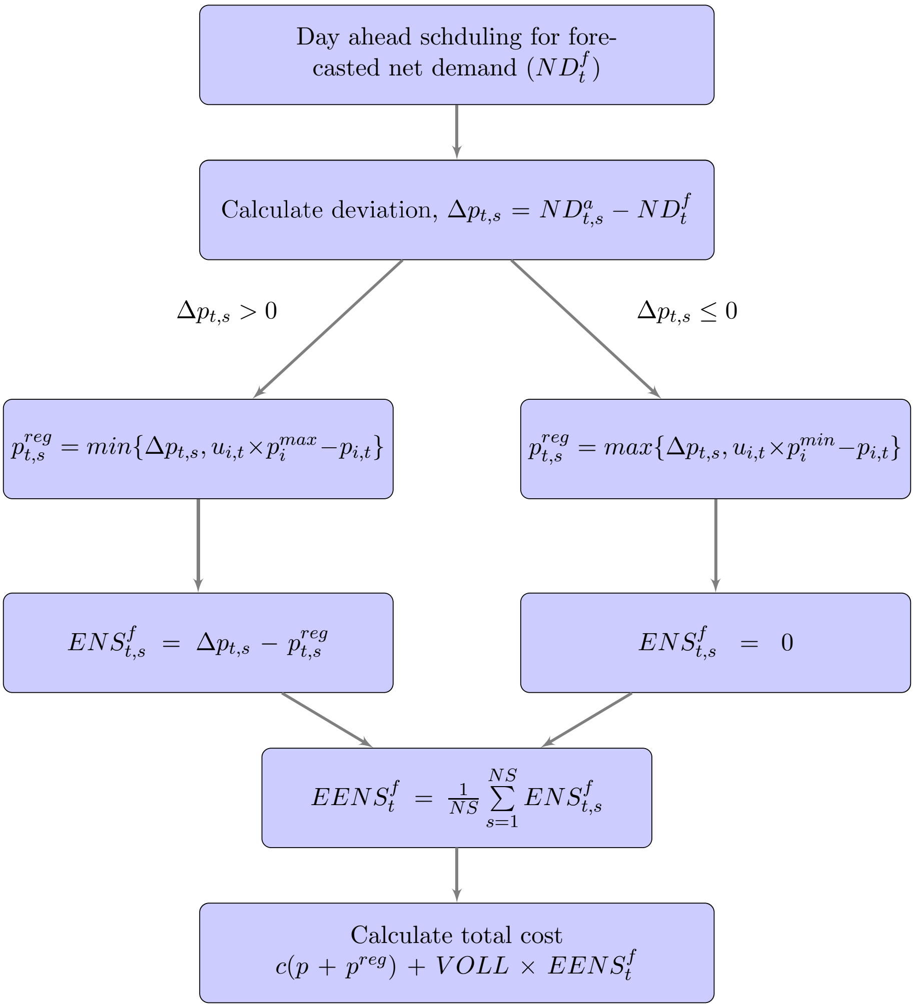

Figure 3.8: Formulation of day-ahead scheduling considering forecast error

3.4.2 Simulation Results

3-Unit System

Figure 3.9 shows different costs with varying SD with VOLL of 1000 \$/MWh. From 0% to 7.5% of SD, the net demand scenarios ranges between 259.10 MW and 390.40 MW. MOC of generators would be sufficient to handle the probability of net demand scenarios. Therefore unserved energy is zero as all the net demand scenarios are well within the limits of MOC bounds. At 10% of SD, the range of net demand scenarios increases to 244.52 MW and 426.16 MW. MOC of 400 MW cannot support net demand scenarios greater than 400 MW. This leads to unserved energy which in this case is 0.19. The UC is the same as before while average ENS from all the scenarios is low to make the third unit commit. The change in the generator schedule is because the system tries to find a feasible generator schedule based on all the scenarios. At 12.5% of SD, the range of net demand scenarios increases to 215.94 MW and 436.08 MW. In this case an additional unit (unit-3) is committed to compensate the probability of net demand scenarios greater than 400 MW of MOC. Thus making unversed energy zero thereby decreasing the total cost.

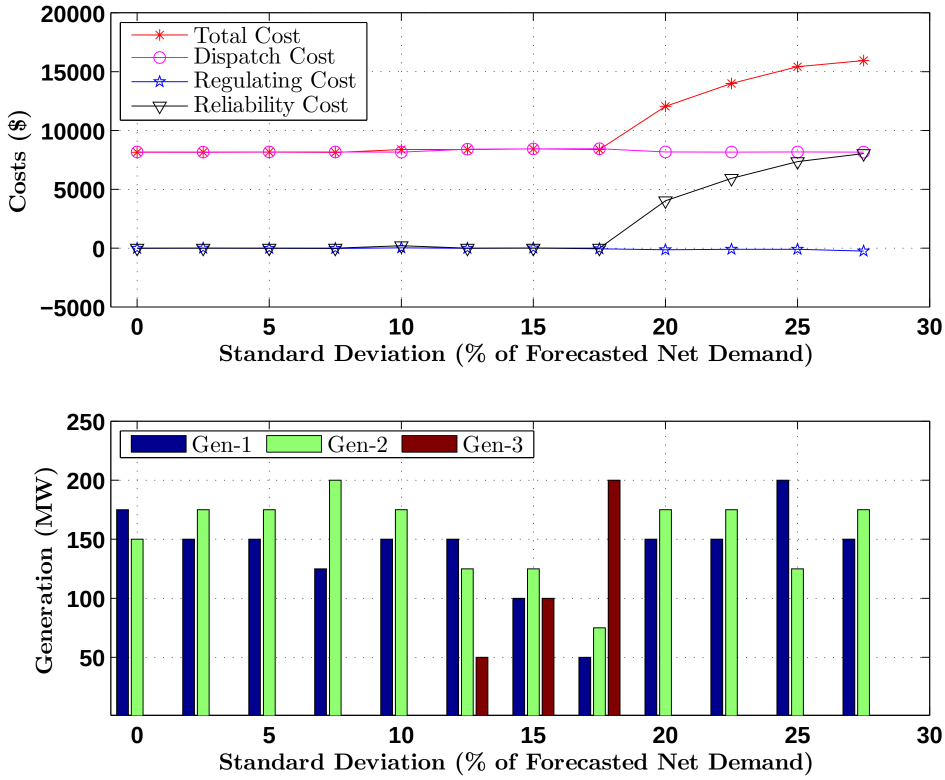

Figure 3.9: Different costs with increasing SD, for a VOLL of 1000 \$/MWh

Until 17.5% of SD, there is no unserved energy as net demand forecasting error is considered in the day ahead market clearing. The net demand scenarios ranges between 158.13 and 509.62 MW. At 20% of SD, this range further increases to 131.4038 MW and 501.02 MW. Even though the higher net demand scenarios can be satisfied with the MOC of generators, the lower net demand scenarios would not be satisfied which makes unit-3 turn off based on (3.39). In other words, as the lower scenarios go below 150 MW (cumulative on-line minimum generator limits), unit-3 is de-committed, which increases unserved energy and thus increased total cost. Further increase in SD will increase the range of net demand scenarios where higher net demand scenarios cannot be compensated leading to increase in unserved energy. This increment can be seen from 20% - 27.5% SD. This increased cost is addressed in subsequent sections.

36-Unit System

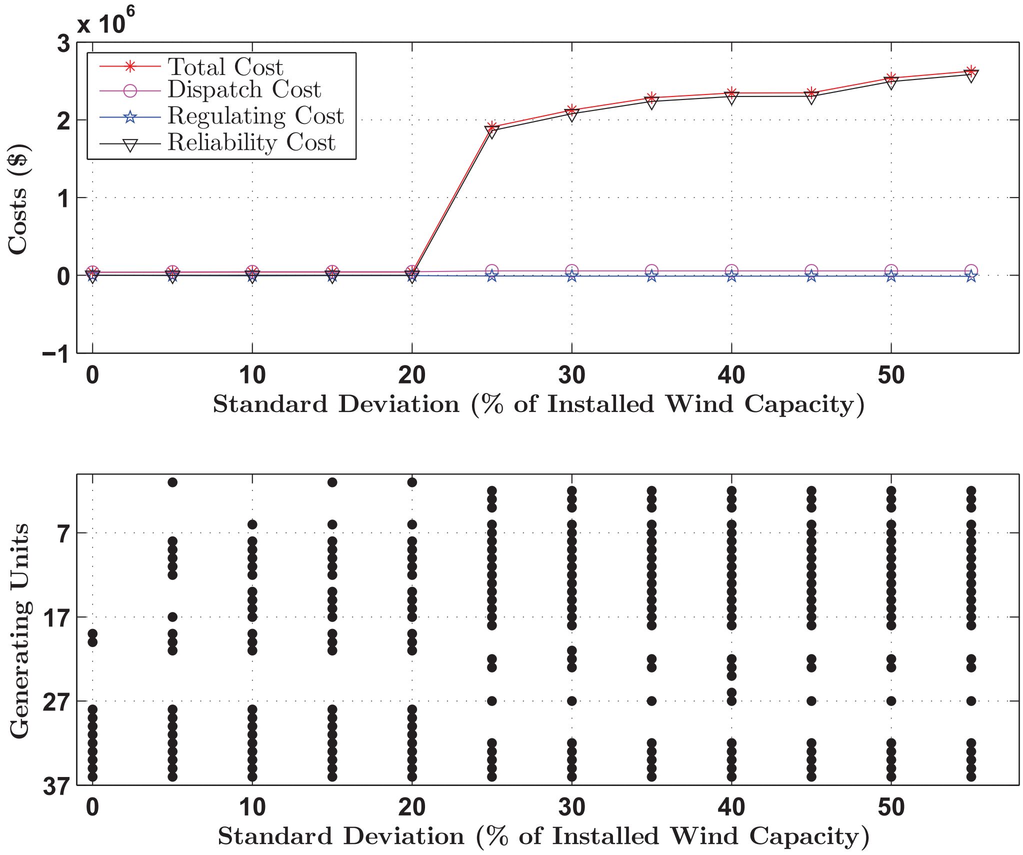

Figure 3.10: Different costs with increasing SD, for a VOLL of 6000 $/MWh

Figure 3.10 shows UC, different costs with increasing SD of wind forecasting error. As the SD of net demand forecasting error increases above 20 % of the total installed wind capacity the higher actual net demand scenarios go out of the MOC bounds, simultaneously the lower scenarios will decrease to less than the cumulative minimum generation limits for the forecasted net demand. The system needs to satisfy the probability of both higher and lower net demand scenarios. Reduced total cost compared to figure 3.7 is because the regulating cost due to wind forecasting error and the reliability cost are considered within the optimization.

Until SD of 20 % there is no unserved energy as the net demand scenarios are within the MOC bounds of the ON generators. At 25 % of SD, the net demand scenarios ranges between 755.4028 MW and 4690 MW. The MOC in this case is 3710 MW. To satisfy the forecated net demand of 3690 MW the system must have a cumulative minimum online generation of 963 MW. There are three net demand scenarios (942.3156, 755.4028, 771.4619) which cannot be compensated as the system should primarily satisfy the day ahead net demand forecast 3690 MW. According to (3.39) these lower scenarios cannot be compensated, as the system needs to have all the net demand scenarios greater than 963 MW. Even though this case do not allow wind curtailment, the system still needs to curtail a portion of wind in order to be physically possible to operate in reality and to have feasible solution. So these lower scenarios are now truncated at 963 MW. The average wind energy curtailed in this case to allow the system to have a solution is given as

$$\frac{(963 - 942.3156) + (963 - 755.4028) + (963 - 771.4619)}{1000} = 0.4198 \tag{3.42}$$

Table 3.2 shows the amount of wind curtailed to have a possible integer solution. Although in reality the case of infeasible solution does not exist, this is an extreme case where wind is very high compared to the system demand. It can be seen that the amount of wind curtailed to have a integer solution increases with increase in SD of net demand foreacasting error. This is obvious as increase in SD will increase the range of net demand scenarios which lead to increase in net demand scenarios less than the cumulative minimum online generator limits. With further increasing in SD from 25% of wind forecasting error, scenarios higher than the MOC leads to ENS thereby increasing the total cost. The dispatch cost is not constant because in this case, the regulating cost due to wind forecasting error is included in the optimization.

Table 3.2: Allowed wind curtailment for feasible solution

SD	Curtailment for feasible solution, MW
<25	0
25	0.4198
30	1.6765
35	3.4309
40	12.4838
45	17.3120
50	19.5800
55	23.8836

3.5 Economic Value of Wind Energy Curtailment

Figure 3.11 shows the reduction in total cost of incorporating wind curtailment and stochastic nature of net demand in the day ahead spot market clearing. Total cost without allowing wind curtailment is higher compared to the deterministic because the higher net demand scenarios are not compensated as there are net demand scenarios lower than cumulative online generator limits. This does not happen in deterministic case as the objective function is to optimize the dispatch cost only. An interesting point to note here is that when considering forecasting error in the day ahead spot market clearing, wind curtailment should also be considered to have better economic reliability. Figure 3.11 shows the difference in total cost of deterministic case compared to considering net demand forecasting error case.

The case when the net demand forecasting error is included in the optimization has higher costs compared to deterministic case. This is because the case with net demand forecasting error the program tries to turn ON the small generators based on (3.39). This will increase the dispatch cost as more costly generators are turned ON. Also the MOC will decrease compared to the deterministic case. At 25% SD, the MOC in case of deterministic case is 3710 MW while the case considering net demand forecasting error is 3695 MW. All the net demand scenarios exceeding MOC lead to unserved energy. The average unversed energy in deterministic case is 302.97 MW while the case considering net demand forecasting error is 310.23 MW. Total cost difference is due to the increase in dispatch cost and reliability cost. These results are subjected to different penetration levels of wind which can be further investigated.

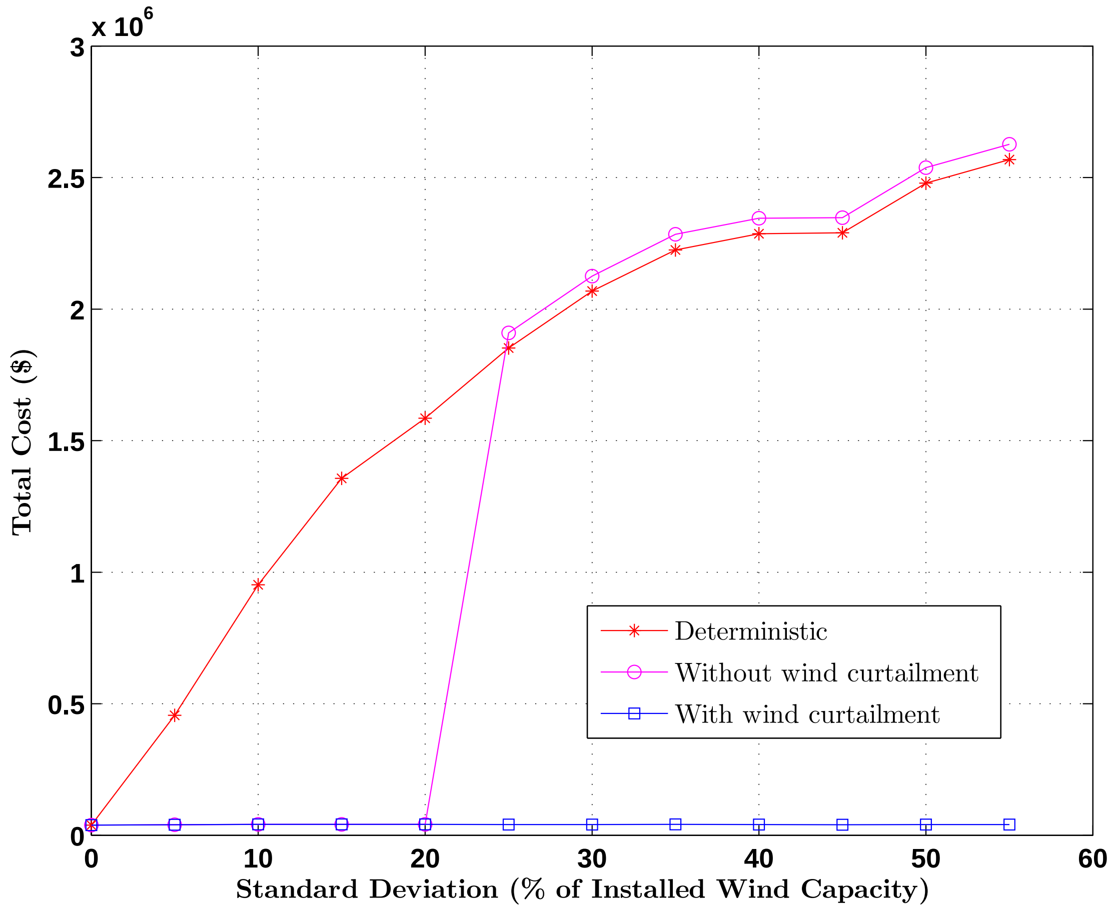

Figure 3.11: Total cost of system operation considering net demand forecasting error

Chapter 4

Conclusions and Future Work

4.1 Conclusions

In this thesis a mathematical model that optimizes the total cost of system operation and evaluates the economic value of wind energy curtailment under the market rules of Nordic power systems has been formulated. In the present system, wind forecasting error is not considered in the day ahead market clearing. In the real time operation, the risk of handling the power system balance will therefore be burdensome for the TSO. Too low wind in the real time operation would trigger the need to turn ON the thermal plants which would stress the generators ramp limits and may increase carbon foot print. Too high wind during real time operation could have a similar environmental impact. In financial terms it may prove to be unprofitable for the GENCOS and uneconomical for the system. Furthermore the reliability of the system would be at stake. To address this scenario, a mathematical model is formulated in this thesis which considers the stochastic nature of wind in the day ahead market clearing. The proposed model would decrease the total system cost considerably.

To analyze the effect of wind and load uncertainty on the system, initially a 3-unit system and later a 36-unit system are considered. The combined effect of load and wind (net demand) forecasting error is analyzed with the three approaches. In the first approach, optimization does not consider reliability cost due to net demand forecasting error during the day ahead spot market clearing. Unserved energy is regarded as an outcome of UC decision making and is formulated as energy that cannot be met by the available maximum online capacity. If the error is within the generation limits total power will be provided by the available generators in the form of regulating power.

In the second approach, optimization considers reliability cost due to net demand forecasting error during the day ahead spot market clearing. This approach clearly reduces the total cost compared to the first approach. However, for higher SD's of net demand forecasting error unserved energy increases. As the range of net demand scenarios widens system tend to satisfy both lower and higher scenarios. While satisfying lower net demand scenarios higher net demand scenarios cannot be compensated which leads to unserved energy. In other words, when the actual scenarios are less than the cumulative minimum online generator limits the system cannot compensate higher net demand scenarios them as a result ENS increases.

In the third approach wind energy curtailment is incorporated. Wind energy curtailed will satisfy the cumulative minimum generation limits. Both the EENS and the total generation cost are considered in the day ahead spot market clearing. In the first approach irrespective of value of lost load, the new unit will not commit even with very high actual net demand scenario while in second approach with high value of VOLL it will commit new units. In both approaches the overall cost is increasing with increasing SD of net demand forecasting error. The third approach is highly recommended as it clearly reduces the overall cost of operation than the two other previous approaches.

4.2 Future Work

This thesis can be further augmented by the following tasks:

- This work can be extended for a practical power system with transmission lines. Transmission line constraints, component outages, stochastic load nature, distributed generation profile, reactive power support and their combined effect on optimal system operation would be interesting to analyze.
- Energy curtailment cost (ECT) can be taken into account to reflect the wind spillage in the UC decision making.
- Conditional Value at Risk (CVaR) can be included in the UC decision making so as to account for the additional risks of extreme system operation situations.
- The calculation of regulating power cost can be determined with respect to the regulating power bids submitted to the TSO in the power market.

Appendix A

Description of Generators

A.1 36 Unit System

Table A.1: Generating units'(1-15) production limits and coefficients of the quadratic cost function [18]

Unit no (i)	p_i^{min}	p_i^{max}	a_i (\$/MW^{2}h)	b_i (\$/MWh)	c_i (\$/h)
1	2.4	12	0.02533	25.5472	24.3891
2	4	20	0.01561	37.9637	118.9083
3	4	20	0.01359	37.777	118.4576
4	4	20	0.01161	37.9637	118.9083
5	4	20	0.01059	38.777	119.4576
6	4	20	0.01199	37.551	117.7551
7	4	20	0.01261	37.6637	118.1083
8	15.2	76	0.00962	13.5073	81.8259
9	15.2	76	0.00876	13.3272	81.1364
10	15.2	76	0.00895	13.3538	81.298
11	15.2	76	0.00932	13.4073	81.6259
12	25	100	0.00623	18	217.8952
13	25	100	0.00599	18.6	219.7752
14	25	100	0.00612	18.1	218.335
15	25	100	0.00588	18.28	216.7752

Table A.2: Generating units'(16-36) production limits and coefficients of the quadratic cost function [18]

Unit no (i)	p_i^{min}	p_i^{max}	a_i (\$/MW^{2}h)	b_i (\$/MWh)	c_i (\$/h)
16	25	100	0.00598	18.2	218.7752
17	25	100	0.00578	17.28	216.7752
18	25	100	0.00698	19.2	218.7752
19	54.25	155	0.00473	10.7154	143.0288
20	54.25	155	0.00481	10.7367	143.3179
21	54.25	155	0.00487	10.7583	143.5972
22	68.95	197	0.00259	23	259.131
23	68.95	197	0.0026	23.1	259.649
24	68.95	197	0.00263	23.2	260.176
25	68.95	197	0.00264	23.4	260.576
26	68.95	197	0.00267	23.5	261.176
27	68.95	197	0.00261	23.04	260.076
28	140	350	0.0015	10.8416	176.0575
29	140	350	0.00153	10.8616	177.0575
30	140	350	0.00143	10.6616	176.0575
31	140	350	0.00163	10.9616	177.9575
32	100	400	0.00194	7.4921	310.0021
33	100	400	0.00195	7.5031	311.9102
34	100	400	0.00196	7.5121	312.9102
35	100	400	0.00197	7.5321	314.9102
36	100	400	0.00199	7.6121	313.9102

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