LOCATIONAL EFFECTS OF VARIABILITY OF POWER GENERATION AND LOADS ON TOTAL COST OF POWER SYSTEMS

by

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To lovely people of Iran

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ABSTRACT

In this thesis locational prices associated with power injection variability are introduced. Using a probabilistic DC optimal power flow (DC-OPF), the sensitivity of uncertainty in injected power on system cost is calculated. This sensitivity may be used as a price for regulation to equitably allocate costs associated with tracking power injections. In this context the price also provides a locational value to energy storage and hence is predicted to provide motivation for those loads and generators with variability to use it as a tool to investigate best locations for energy storage. As a case study, the IEEE 24-bus test system with uncertain variable wind power and uncertain variable loads is analyzed. Three scenarios are posed to consider changes in network's parameters. In the first scenario only two wind generators are uncertain and the loads considered to be deterministic. In the second scenario, all loads and the two generators have the same amount of uncertainty. Finally in the third scenario, different values of uncertainty are associated with different locations.

Chapter 1

Introduction

Electric power injections in the grid are continuously varying as end-use loads turn on/off, shift demand, and certain renewable resources vary with changes in input (wind,solar). It is one of the tasks of grid operation to manage resources to track and respond to load changes. On a slow time-scale over hours, diurnal load patterns are accommodated by economic adjustments in generation output, often procured at least cost through an energy market. On a fast time-scale spanning seconds to minutes in which it is impractical to operate similar markets, power imbalance is addressed through automatic control of certain generators that supply ”regulation” services. The chosen suppliers of this service may be selected via a market for regulation services. The amount of power needed for power balancing regulation depends on the location and variability of power injections present in the system, however the most typical policy for payment of regulation shares the cost among network users, regardless of user variability.

In this thesis we introduce a means to price variability in terms of a sensitivity of system cost to locational power injection variation. Such a price is practical in that it prices the incremental cost of variable power injections, and it can be used to equitably allocate charges to those entities with variable power injections. These include traditional loads, and increasingly intermittent generation such as wind and solar power. It is also important as technologies evolve to mitigate power variations through energy storage. Placing a price on variability provides a means to value storage by location. This can influence the coupling of solar and wind installations with energy storage options.

The pricing of variable power injections couples well with energy markets that already have regulation markets, and that also accommodate wind and solar generation, such as Independent System Operators in the United States.

Electricity Markets and Independent System Operators

Before 1990s the electricity industry was dominated by integrated utilities. In the U.S. there was integration between generation, transmission, distribution and retailing which resulted in a lack of competition in generation [5].

It was believed that there is a natural monopoly in generation of electricity, but technological developments which made scale economies less important (specially in large networks [6]) and also costly inefficient investments in generation, encouraged policy makers to have a competitive electricity market. Competition among generator units seemed more cost efficient and also more reliable.[7] The argument was that if competition exists in electricity market, labour and fuel consumption will be rationalized, investment decision would be more reasonable, and the quality of customer services will improve.

To overcome absence of competition and traditional vertically integrated utilities, efforts in liberalization of the market were made, including separation of ownership of transmission from generation, and also creation of electric energy markets to support competition. In the US, ISOs (Independent System Operators) were introduced to operate the markets and manage the grid. The characteristics of an ISO has been determined by Federal Energy Regulatory Commission (FERC) to be [8]

- ISO should be independent from individual market participants. ISO and its employees should not have any financial benefit in economic performance of any of market participants.
- ISO should act in a fair and non-discriminatory manner.

- ISO should provide open access for every participant in the electricity market to transmission system via a single, unbundled, grid-wide tariff which is applied to every participant of the network in a non-discriminatory manner.
- ISO should ensure about short-term reliability grid operations based on NERC standards
- ISO should be able to take operational actions to relieve constraints within trading rules in order to promote efficient trading
- ISO is responsible for efficient management and administration in an open market and is responsible to provide services needed for such a management
- ISO's pricing in the system should provide motivation for investment in the generation, transmission and consumption and ISO is responsible to investigate the network for further expansion
- ISO is responsible to make system's information publicly available in specific intervals
- ISO is responsible to manage coordination with neighbouring areas
- ISO is responsible to establish an alternative dispute resolution in order to dispute possible disputes in the network
- ISO has authority over physical dispatch of plants

Functions and duties comprise

- ISO should make sure that system has minimum possible congestion
- Design tariff prices
- Manage Parallel path flows
- Management of transmission of services including generation reserves, voltage control services, power loss replacement

- Avoiding price manipulation by continuous monitoring of the market
- Planning for expansion of the network

These are a lot of tasks. In this thesis we focus on only those tasks related in part to the procurement of energy reserves for regulation services, which necessarily couples with energy markets. Typically, ISOs operate day-ahead and real-time energy markets. ISO/RTO council members map can be seen in Figure 1.1.

A day-ahead market contains an auction for energy and may include regulation and operating reserves. If the energy, regulation or operating reserve which has been sold in day-ahead, is not eventually physically transmitted, it need be bought back. In most day-ahead markets, offers are due in the middle of day before the target day. For example, in the MISO, the market offer period closes at 11:00 a.m. of the previous day, reliability unit commitment opens for offers at 17:00 and closes at 18:00, and the results for reliability unit commitment are posted at 20:00. Generally, day-ahead market consists of three price components; No load, Start-up, Incremental energy. Incremental energy means the minimum price which the seller is interested to sell its service (energy) and if this price is negative it represents maximum acceptable price which the seller can pay to supply energy at a certain level which is physical load level of its generators. In a day-ahead auction, the market price is calculated as Lagrange multipliers of the power balance constraint in the optimization problem associated with the auction. Some markets include regulation and operating reserves markets in their day-ahead market while some others include regulation and operating reserves in their real-time market.

A real-time market contains an auction for energy and also an auction for deviations from day-ahead schedules. If there is some amount of demand and it is not supplied in the day-ahead market, it will be supplied via the capacity of generators who are participating in real-time market. Also if locational marginal pricing is being used, then marginal congestion and marginal loss charges are calculated for any transactions through real-time market.

In a real-time market, bids contain two categories; the new offers which have been submitted subsequent to the day-ahead market, and offers who have been submitted to the day-ahead

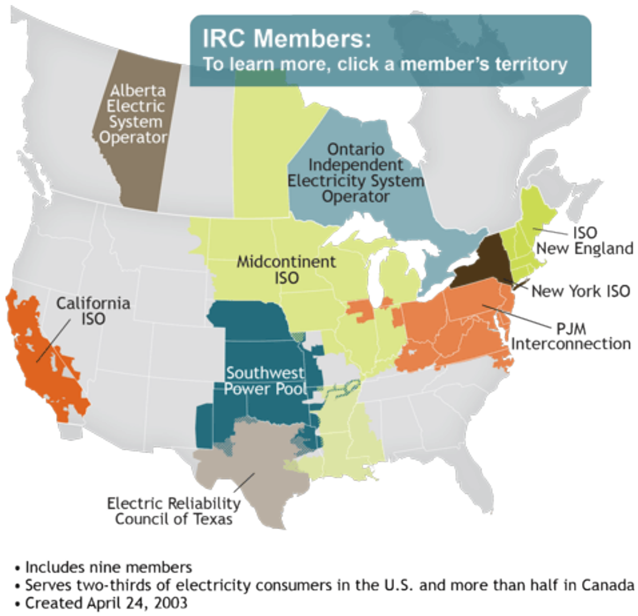

Figure 1.1 ISO/RTO council members [1]

market but have not been accepted. Although the prices are calculated on 5-15 minutes basis, at each location the market is settled using single hourly integrated price. The ISO sends prices and outputs to generators every 5 to 10 minutes and then measures the actual output of those generators.

Faster adjustments to generation are made through automatic generation control to those units supplying regulation services. The need for regulation services increases with variable power injection. Traditionally the variability has been due to load fluctuations, however new variable energy sources include wind power and solar generation. Trends certainly suggest that these sources will become a greater part of the total electric energy supply and accommodating their variations will require increased regulation services, energy storage, or both.

Sample variable outputs from wind and solar generation is shown in Figures 1.2, and 1.3. These clearly show significant power injection variations on time-scales shorter than a minute.

This link between variability, regulation services, and renewable energy sources is important as many states and countries have adopted policies to encourage (and even mandate) supply from renewable resources. Increasing the market penetration of common renewable

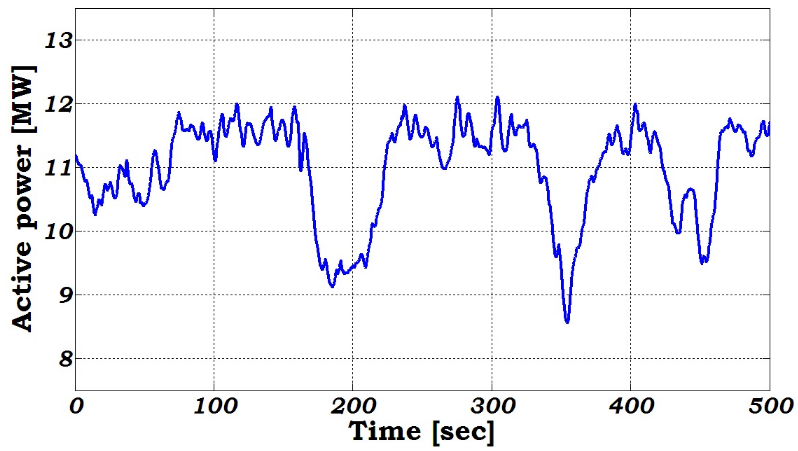

Figure 1.2 Wind time series in ASIG wind farm [2]

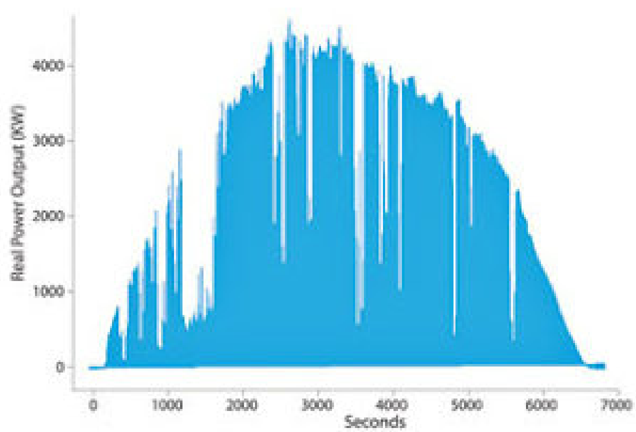

Figure 1.3 Real Power output of a Solar Power Plant [3]

energy technologies will increase the variability of power injections and power flows in the grid. Somewhat ironically, this necessitates additional controllable resources to provide more regulation in the current framework. We posit that a locational regulation price will provide an incentive to both smooth power injections at variable source locations, and encourage non-traditional technologies to supply regulation such as demand response.

Other papers have investigated different aspects of energy storage in the grid. In [9] the role of energy storage on an electricity grid in the presence of renewable energy as well as different scenarios to design energy storage systems has been discussed. In [10] the properties of storage to allow more use of renewable energy in the network has been discussed. In [11] the appropriate size of storage systems has been investigated. In [12] financial analysis has been implemented to compute electricity storage systems cost. See [13, 14] for calculation of cost of storage and [15] for discussion about different categories of energy storage technologies. This paper differs by introducing a locational regulation price that can be used to value storage. The price that we compute here is a marginal cost equal to the sensitivity of total system production cost to a locational measure of power injection variability. This is cast as a sensitivity of a probabilistic DC optimal power flow where the measure of variability is taken as statistically as a standard deviation of power injection. Other measures are possible, but not pursued in this thesis.

This thesis is organized as follows. Chapter 2 presents the problem formulation and the deviation of the proposed method to computer price, Chapter 3 investigates some case studies and numerical results based on IEEE One area RTS-96 system. Chapter 4 includes further investigation of the problem and relationship between different parameters of the network. Conclusions are presented in Chapter 5.

Chapter 2

Formulating The Problem

In this chapter, a probabilistic DC Optimal Power Flow formulation is presented. Using this model a sensitivity analysis of the probabilistic optimal power flow is used to develope a price associated with power injection variability.

2.1 Formulation of a Probabilistic DC-Optimal Power Flow

The optimal power flow (OPF) was introduced in the early 1960s [16]. The aim of th OPF is to find the least-cost operating point considering constraints over transmission lines, voltage , power generation, etc. The simpler, commonly-used DCOPF is obtained by linearizing the ACOPF assuming all voltage magnitudes are fixed and voltage angle differences are small [17].

A standard DC optimal power flow formulation is

$$\min C_G^T P_G \tag{2.1}$$

subject to

$$EP_G - B\theta = P_L \tag{2.2}$$

$$P_G^{min} \leq P_G \leq P_G^{max} \tag{2.3}$$

$$-P_{ij}^{max} \leq \frac{1}{x_{ij}}(\theta_i - \theta_j) \leq P_{ij}^{max},\ \forall ij \tag{2.4}$$

$$\theta_{slack} = 0 \tag{2.5}$$

where P_G is active power injections, θ is the voltage angles, P_G^{max} is upper nominal production level, P_G^{min} is lower nominal production level, P_L is vector of loads x_{ij} is line reactance for line ij, B is a matrix related to the bus admittance matrix and E is an indicator matrix with all elements are 0 or 1 and when is multiplied by P_G gives the vector of generated power on each bus. In particular matrix E maps the generation of multiple generators at a bus to a net bus injected power.

We follow a probabilistic approach to adjust this model to accommodate uncertainties in power injections. Specifically we use the analytic approach described in detail in [4] in which generation and transmission constraints are enforced with a user-specified probability. That paper focused on variable wind generation. We augment their example to also consider variations in load, mathematically treated as negative generation, and we compute sensitivities to introduce a regulation price. Introducing random variations in power injection leads to changes on both transmission line and generation capacity constraints, equation (2.3) and equation (2.4)

$$\mathbf{Prob}\left[\frac{1}{x_{ij}}(\theta_i - \theta_j) + \sum_{G=1}^{N_G} GF_{ij,G}\Delta P_{G,G} - P_{ij}^{max} \leq 0\right] \geq 1 - \epsilon \tag{2.6}$$

$$\mathbf{Prob}\left[P_{G,g} + \sum_{G=1}^{N_G} D_{g,G}\Delta P_{G,G} \leq P_{G,g}^{max}\right] \geq 1 - \epsilon \tag{2.7}$$

where GF is a $N_l \times (N_G + N_G)$ matrix of generalized generation distribution factors. N_l is number of transmission lines, N_G is number of generators which have uncertainty, N_G is number of conventional generators, ϵ is violation probability and D is weighting matrix of changes in generation due to deviation from schedule.

When there are changes in the sysetm due to uncertainty of G, each generator plays a role to compensate these changes, element $D_{g,G}$ is the ratio of the change ($\Delta P_{G,G}$) which is compensated by generator g. Also here $\Delta P_{G,G}$ is the variation in generated power which is resulted from variations in generator G. Matrix D is defined as

$$D_{g,l} = \frac{P_{G,g}^{max}}{\sum_{j=1,j\neq l}^{N_G} P_{G,j}^{max}} \tag{2.8}$$

where $D_{g,l}$ describes changes in generator g due to variations in generator l. Generalized generation distribution factors are defined by

$$GF_{ij}^{l} = \frac{1}{x_{ij}} e_{ij} X r_l \tag{2.9}$$

where e_{ij} is a row vector which all of its entries are zero except the ith column which is $+1$ and jth column which is -1. Also x_{ij} is the reactance of line which connects buses i and j, and X is the bus reactance matrix. r_l describes the changes which happen in other buses when power generation at generator l varies. For example, consider a generator l located at bus k; then for k-th row of r_l we can write equation (2.10) and for other rows which correspond to buses which generator k is not located on them equation (2.11) could be written

$$r_l(k) = \frac{\sum_{g \in bus\#k, g \neq l} P_{G,g}^{max}}{\sum_{m=1, m \neq l}^{N_G} P_{G,m}^{max}} - 1 \tag{2.10}$$

$$r_l(i) = \frac{\sum_{g \in bus\#i} P_{G,g}^{max}}{\sum_{j=1, j \neq l}^{N_G} P_{G,j}^{max}} \tag{2.11}$$

If we model the variations by a Gaussian random distribution we can express (2.6) and (2.7) as

$$\frac{1}{x_{ij}}(\theta_i - \theta_j) \leq P_{ij}^{max} - \Phi^{-1}(1-\epsilon)\sqrt{\sum_{G=1}^{N_G} GF_{ij,G}^{2} \sigma_G^2} \tag{2.12}$$

$$P_{G,g} \leq P_{G,g}^{max} - \Phi^{-1}(1-\epsilon)\sqrt{\sum_{G=1}^{N_G} D_{g,G}^{2} \sigma_G^2} \tag{2.13}$$

Here ϕ^{-1} is inverse of standard normal distribution function and σ_G is standard deviation of generator G's power generation's distribution function.

In summary, equation (2.4) in the DC optimal power flow will be replaced by equation (2.12), and the right hand side of equation (2.3) is replaced by equation (2.13). We solve this probabilistic DCOPF for P_G and θ. Then we perform a sensitivity analysis to compute a price.

2.2 KKT Conditions, Sensitivity analysis, Linearization (Proposed method)

Using the probabilistic DC-OPF formulas, the KKT conditions can be written. Define

$$\Xi = \sqrt{\sum_{G=1}^{N_G} GF_{ij,G}^2 \sigma_G^2}, \quad \forall i, j \tag{2.14}$$

and write the corresponding Lagrangian as

$$\begin{aligned}\mathcal{L} &= C_G^T P_G + \lambda_G^T (EP_G - B\theta - P_L) \\ &+ \lambda_M^T (P_G - P_G^{max}) \\ &+ \lambda_m^T (P_G^{min} - P_G) \\ &+ \lambda_S^T \left(-P_{Line}^{max} + \Phi^{-1}(1-\epsilon)\Xi + \tilde{x}\Omega\theta\right) \\ &+ \lambda_R^T \left(-P_{Line}^{max} + \Phi^{-1}(1-\epsilon)\Xi - \tilde{x}\Omega\theta\right)\end{aligned} \tag{2.15}$$

where θ is voltage angle vector, Ω is a $N_l \times N_l$ matrix where N_l is number of transmission lines. At each row of Ω, all elements equal to zero except the i-th column which is $+1$ and jth column which is -1, and $\tilde{x}$ is a $N_l \times 1$ column vector with $1/x_{ij}$ at each row l.

The KKT conditions [18] are

Stationary:

$$\frac{\partial \mathcal{L}}{\partial P_G} = 0 \rightarrow C_G + E^T \lambda_G + \lambda_M - \lambda_m = 0 \tag{2.16}$$

$$\frac{\partial \mathcal{L}}{\partial \theta} = 0 \rightarrow -B^T \lambda_G + \Omega^T \tilde{x}^T \lambda S - \Omega^T \tilde{x}^T \lambda_R = 0 \tag{2.17}$$

Equality Constraints:(Primal Feasibility)

$$EP_G - B\theta = P_L \tag{2.18}$$

Inequality Constraints:(Primal Feasibility)

$$P_{G,g} \leq P_{G,g}^{max} - \Phi^{-1}(1-\epsilon)\sqrt{\sum_{G=1}^{N_G} D_{g,G}^2 \sigma_G^2}, \quad \forall g \tag{2.19}$$

$$-P_G \leq -P_G^{min} \tag{2.20}$$

$$\frac{1}{x_{ij}}(\theta_i - \theta_j) \leq P_{ij}^{max}$$
$$-\Phi^{-1}(1-\epsilon)\sqrt{\sum_{G=1}^{N_G} GF_{ij,G}^2 \sigma_G^2},\ \forall ij \tag{2.21}$$

Complementary Slackness:

$$\lambda_{S_{ij}}\left(-P_{ij}^{max} + \Phi^{-1}(1-\epsilon)\sqrt{\sum_{G=1}^{N_G} GF_{ij,G}^2 \sigma_G^2} + \frac{1}{x_{ij}}(\theta_i - \theta_j)\right) = 0 \quad \forall ij \tag{2.22}$$

$$\lambda_{R_{ij}}\left(-P_{ij}^{max} + \Phi^{-1}(1-\epsilon)\sqrt{\sum_{G=1}^{N_G} GF_{ij,G}^2 \sigma_G^2} - \frac{1}{x_{ij}}(\theta_i - \theta_j)\right) = 0 \quad \forall ij \tag{2.23}$$

$$\lambda_{M_i}(P_{G_i} - P_{G_i}^{max}) = 0, \quad \forall i \tag{2.24}$$

$$\lambda_{m_i}(P_{G_i}^{min} - P_{G_i}) = 0, \quad \forall i \tag{2.25}$$

Dual Feasibility:

$$\lambda_R \geq 0 \tag{2.26}$$

$$\lambda_S \geq 0 \tag{2.27}$$

$$\lambda_M \geq 0 \tag{2.28}$$

$$\lambda_m \geq 0 \tag{2.29}$$

Having the formulation above we solve the optimization problem and find P_G^*, θ^*, λ_M^*,λ_m^*, λ_S^*, λ_G^*, λ_R^* and linearize all equations around the solution.

We linearize the KKT conditions around the solution, only including binding constraints because the sensitivity is calculated as a derivative, non-binding constraints have no effect. We obtain

$$\Delta Cost = C_G \times \Delta P_G \tag{2.30}$$

$$E^T \Delta\lambda_G + \Delta\lambda_M - \Delta\lambda_m = 0 \tag{2.31}$$

$$-B^T \Delta\lambda_G + \Omega^T \tilde{x}^T \Delta\lambda_S - \Omega^T \tilde{x}^T \Delta\lambda_R = 0 \tag{2.32}$$

$$E\Delta P_G - B\Delta\theta = 0 \tag{2.33}$$

$$\Delta\lambda_{M_i} = 0, \quad i \notin E \tag{2.34}$$

$$\Delta P_{G_i} + \frac{(\Phi^{-1})^2}{\gamma}(D^2_{g,G_1}\sigma_1^*\Delta\sigma_1 + D^2_{g,G_2}\sigma_2^*\Delta\sigma_2) = 0 \quad \forall i \in E \tag{2.35}$$

while

$$\gamma = \Phi^{-1}(1-\epsilon)\sqrt{\sum_{G=1}^{N_G} D^2_{g,G}\sigma^2_G}$$

$$E = \{7, 8, 15, 21, 23, ..., 33\}$$

$$\text{diag}(P_G^{min} - P_G^*)\Delta\lambda_m + \text{diag}(\lambda_m^*)\Delta P_G = 0 \tag{2.36}$$

$$\lambda^*_{R_{ij}}\left(\Phi^{-1}(1-\epsilon)\frac{GF^2_{ij,G_1}(\sigma_1^*)\Delta\sigma_1 + GF^2_{ij,G_2}(\sigma_2^*)\Delta\sigma_2}{\sqrt{GF^2_{ij,G_1}\sigma_1^2 + GF^2_{ij,G_2}\sigma_2^2}} - \frac{1}{x_{ij}}(\Delta\theta_i - \Delta\theta_j)\right) = 0, \quad ij = 23 \tag{2.37}$$

$$\Delta\lambda_{R_{ij}}\left(-P_{ij}^{max} + \Phi^{-1}(1-\epsilon)\sqrt{GF^2_{ij,G_1}\sigma_1^{*^2} + GF^2_{ij,G_2}\sigma_2^{*^2}} - \frac{1}{x_{ij}}(\theta_i^* - \theta_j^*)\right) = 0, \quad ij \neq 23 \tag{2.38}$$

$$\Delta\lambda_{S_{ij}}\left(-P_{ij}^{max} + \Phi^{-1}(1-\epsilon)\sqrt{GF^2_{ij,G_1}\sigma_1^{*^2} + GF^2_{ij,G_2}\sigma_2^{*^2}} + \frac{1}{x_{ij}}(\theta_i^* - \theta_j^*)\right) = 0 \tag{2.39}$$

$$\Delta\lambda_{R_{ij}} = 0, \quad ij \neq 23 \tag{2.40}$$

$$\Delta\lambda_{S_{ij}} = 0, \quad ij \in \{1, ..., 24\} \tag{2.41}$$

Here we introduce a measure of price of regulation by using the above linearized formulas. Our proposed price is $\Delta Cost/\Delta\sigma$ and can be obtained by forming the following system of equations

$$\mathcal{Q} \times \mathcal{V} = \Lambda \tag{2.42}$$

where $\mathcal{V}$ is the vector of variables

$$\mathcal{V} = \begin{bmatrix} \Delta P_G & \Delta\lambda_G & \Delta\lambda_M & \Delta\lambda_m & \Delta\lambda_S & \Delta\lambda_R & \Delta\theta & \Delta\sigma \end{bmatrix}^T \tag{2.43}$$

$$= \begin{bmatrix} \tilde{\mathcal{V}} & \Delta\sigma \end{bmatrix}^T \tag{2.44}$$

Split matrix $\mathcal{Q}$ as

$$\mathcal{Q} = \begin{bmatrix} Q_{11} & Q_{12} \\ Q_{21} & Q_{22} \end{bmatrix} \tag{2.45}$$

and note that the right-hand side vector (Λ) is a vector of all zeros except the row which corresponds to equation (2.30) which has $\Delta Cost$ on the right-hand side. Hence the equation (2.42) can be written as

$$\begin{bmatrix} Q_{11} & Q_{12} \\ Q_{21} & Q_{22} \end{bmatrix} \begin{bmatrix} \tilde{\mathcal{V}} \\ \Delta\sigma \end{bmatrix} = \begin{bmatrix} \Delta Cost \\ \mathbf{0} \end{bmatrix} \tag{2.46}$$

where **0** is a vector of all zeros. Then

$$Q_{11} \times \tilde{\mathcal{V}} + Q_{12} \times \Delta\sigma = \Delta Cost \tag{2.47}$$

$$Q_{21} \times \tilde{\mathcal{V}} + Q_{22} \times \Delta\sigma = \mathbf{0} \tag{2.48}$$

from (2.48) we have that

$$\tilde{\mathcal{V}} = -Q_{21} Q_{22} \Delta\sigma$$

and hence

$$Q_{11}(-Q_{21}^{-1}Q_{22}\Delta\sigma) + Q_{12}\Delta\sigma = \Delta Cost$$
$$\Rightarrow \frac{\Delta Cost}{\Delta\sigma} = -Q_{11}Q_{21}^{-1}Q_{22} + Q_{12} \tag{2.49}$$

In equation (2.49) we have proposed sensitivity of total cost to statistical standard deviation of injected power as a measure of price of regulation. This method has the advantage that price depends to uncertainty and hence customers (buses) which posses more uncertainty and make more unreliability in the network would be penalized and pay bigger part of the regulation price.

Chapter 3

Case Studies and Numerical Results

In this section to investigate the proposed method more precisely, the effect of power injection variability on total cost is studied based on the 24-bus system. This system model corresponds to the IEEE One Area RTS-96 system [19] with the addition of two wind generators installed on buses 8 and 15 (Fig.3.1) with installed capacity of 500 and 700 MW respectively. This example is taken from [4] which considers forecasted wind power in-feed equal to 25% of installed wind power capacity and violation probability (for the chance constraints) to be 5%.

The emergency line limit is $\alpha = 1.1$ and nominal capacity available as regulating power in the case of a contingency is $\beta = 1.25$. The standard deviation($\sigma_1 = \sigma_2$) is considered to be 7.5% of installed capacity.

For the base case (considering wind generators without power injection variability) energy prices and Lagrange multipliers associated with traditional generators' limits are mentioned in Tables 3.1 and 3.2.

The sensitivity of total cost due to variability of loads (or injected power) is also investigated in this chapter. Loads are treated as negative generators and two scenarios are considered related to load variation and wind power variation.

Three scenarios are studied here. The first considers only the wind power variability, as in [4]. The second and third scenarios include load variability. The scenarios are

S1. Considering uncertainty in two buses with wind generators

S2. Considering uncertainty in loads as well as generators when the uncertainty is uniform in all buses

Table 3.1 Energy prices in the base case (system without uncertainty)

Bus #	**Load (MW)**	Energy Price [$/MWh]
1	108	10.239
2	97	10.246
3	180	10.023
4	74	10.265
5	71	10.284
6	136	10.311
7	125	10.306
8	46	10.306
9	175	10.281
10	195	10.331
11	0	10.527
12	0	10.222
13	265	10.277
14	194	10.961
15	142	9.582
16	100	9.537
17	0	9.553
18	333	9.56
19	181	9.703
20	128	9.846
21	0	9.567
22	0	9.561
23	0	9.923
24	0	9.747

S3. Considering uncertainty in loads as well as generators with non-uniform uncertainty in loads

Scenario S1

Wind power variability. The standard deviation in wind power output is taken to be a measure of uncertainty and using this measure of uncertainty, we would calculate regulation price as the sensitivity of production cost to uncertain wind generation.

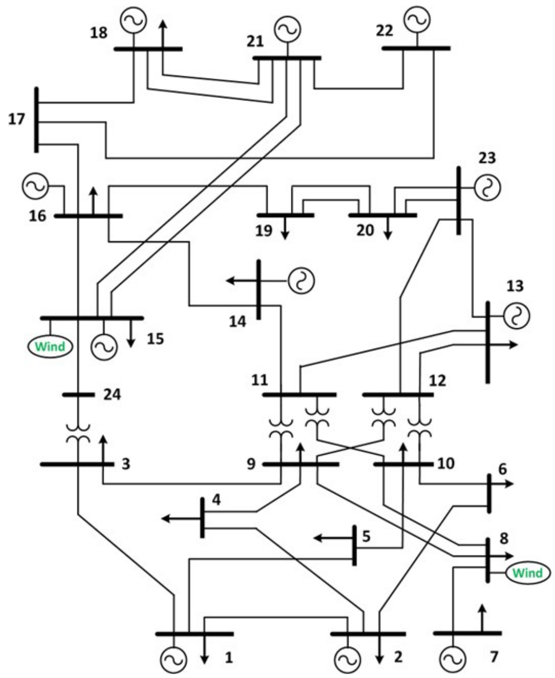

Figure 3.1 24-bus system with wind generators on buses 8 and 15 [4]

In this scenario, only wind generators has been considered as uncertain elements in the network. Using the data provided in the beginning of the chapter, the sensitivities of total cost to variability of wind generators 1 and 2 (500 & 700 MW) are computed and given in Table 3.3. The values are presented in units of $\$/\text{MWh}$. All sensitivities of cost to variability presented in the table for this scenario and all other tables in this thesis are calculated empirically via perturbation analysis.

Scenario S2

In this scenario, all loads and also two wind generators located on buses 8 and 15 have the same variability ($\sigma_L = 1\%$ for all buses, and $\sigma_{G_1} = \sigma_{G_2} = 1\%$). In this case the network maintains uniform uncertainty in all buses. The results can be seen in the Table 3.4

Scenario S3

In this scenario the variability on buses with wind generators are increased. In this case the standard deviation σ_L remains equals to 1% for all buses except buses with wind generators, and for buses with wind generators (buses 8 and 15) standard deviation is substantially increased for loads (σ_L) and wind generators (σ_{G_1} and σ_{G_2}) to be 71%. The results can be seen in Table 3.5

Discussing the Scenarios

The two different load scenarios(S2 and S3) are designed to result in different binding constraints. In scenario S2 the marginal units are generators 3 and 4 with all others at minimum or maximum output. In the scenario S3, generators 3 and 4 are binding, and the units at bus 7 are marginal. In both scenarios there is a single binding line constraint. Line 23 connecting buses 14 and 16, is binding in both cases.

The difference in prices between the two load scenarios are largely driven by a change in binding constraints. We observe that different cases with the same binding constraints in this probabilistic model, the computed regulation prices do not vary, much in the same way that traditional LMP variations are dominated by congestion costs.

Most of the prices obtained from the sensitivity analyses are much smaller than the energy prices except for a few locations. The variability of the power injection at these points has a greater impact on the binding constraints and are more significant. These results show the importance of a location price associated with power injection variability. Next chapter will discuss the affecting factors on these sensitivity values in the network.

Table 3.2 Lagrange multipliers associated with traditional generators' limits in the base case (system without uncertainty)

Bus #	**Gen.** #	$\mathcal{L}_{\mathrm{M}}$	$\mathcal{L}_{\mathrm{m}}$
1	1	14.6	0
	2	14.6	0
	3	0	0
	4	0	0
2	5	14.5	0
	6	14.5	0
	7	0	0.007
	8	0	0.007
7	9	7.6	0
	10	7.6	0
	11	7.6	0
13	12	8.1	0
	13	8.1	0
	14	8.1	0
15	16	0	10.96
	17	11.6	0
	18	11.6	0
	19	11.6	0
	20	11.6	0
16	21	11.6	0
18	22	0	0.04
21	23	0	0
22	24	0	4.33
	25	0	8.56
	26	0	8.56
	27	0	8.56
	28	0	8.56
	29	0	8.56
	30	0	8.56
23	31	0	0.38
	32	0	0.38
	33	0	0.38

Table 3.3 Total cost changes due to variability of injected power

$\Delta Cost/\Delta\sigma_{G_1}$ [$\$/MWh$]	2.3252
$\Delta Cost/\Delta\sigma_{G_2}$ [$\$/MWh$]	2.9238

Table 3.4 Cost changes due to uniform variability of loads (Scenario S2)

Bus #	**Load (MW)**	$\frac{\Delta Cost}{\Delta\sigma_L}$ [$/MWh]	Energy Price [$/MWh]
1	108	0.5558	10.23
2	97	0.5018	10.24
3	180	0.81162	10.02
4	74	0.387	10.26
5	71	0.3788	10.28
6	136	0.7438	10.31
7	125	0.677	10.306
8	46	0.2491	10.306
9	175	0.9233	10.28
10	195	1.0834	10.33
11	0	0	10.52
12	0	0	10.22
13	265	1.3849	10.27
14	194	2.0219	10.96
15	142	0.7106	9.58
16	100	0.5165	9.53
17	0	0	9.55
18	333	1.6972	9.56
19	181	0.8427	9.7
20	128	0.5705	9.84
21	0	0	9.56
22	0	0	9.56
23	0	0	9.92
24	0	0	9.74

Table 3.5 Cost changes due to variability of loads with different variabilities of loads (Scenario S3)

Bus #	**Load (MW)**	$\frac{\Delta Cost}{\Delta \sigma_L}$ [$/MWh]	Energy Price [$/MWh]
1	108	0.1279	17.23
2	97	0.1174	17.31
3	180	0.1088	14.86
4	74	0.0936	17.52
5	71	0.0969	17.73
6	136	0.2028	18.02
7	125	0.1801	17.97
8	46	4.7043	17.97
9	175	0.2289	17.69
10	195	0.3068	18.24
11	0	0	20.39
12	0	0	17.05
13	265	0.334	17.6
14	194	1.201	25.15
15	142	10.5878	10.02
16	100	0.1203	9.53
17	0	0	9.86
18	333	0.3789	9.79
19	181	0.1302	11.35
20	128	0.0679	12.92
21	0	0	9.86
22	0	0	9.8
23	0	0	13.77
24	0	0	11.84

Chapter 4

Further Analysis

In the previous chapter, we presented examples of the proposed method to calculate a price for uncertain power injections. In this chapter, the relation between ϵ and σ_L is investigated. Also effect of changing traditional generators' limits as well as chance constraints probability ϵ and uncertainty σ_L are presented. The purpose is to better understand the effects that influence the proposed price.

4.1 Effects of changing traditional generators' limits on the costs

First the effects of changing traditional generators' limits on the different costs and prices is investigated. The results of various empirical tests are shown in Tables 4.1 and 4.2.

As it can be seen in Tables 4.1 and 4.2 when limits on traditional generators changes from 100 % to 90 % it does not affect Lagrange multipliers corresponding to generator limits and energy prices, but it slightly decreases sensitivity values. On the other hand, if these limits change to 110 %, the energy prices will decrease. One should note that in Tables 4.1 and 4.2 the limits on all generators located on bus # 1 are changed, which includes generators # 1 , #2, # 3, # 4.

In Tables 4.3 and 4.4 generator limits for generators which are located on bus # 15 are changed. The reason to choose this bus and compare them with Tables 4.1 and 4.2 is that bus # 15 is where wind generators are located and therefore in Table 4.3 we are investigating effects of increasing traditional generators limits at a bus with a lot of uncertain (70 %) generation.

As it can be seen, increasing the limits from 90% to 110 % will not change energy prices but will slightly increase sensitivity values. If we increase the limits to 1000 %, still sensitivity values are increasing but energy prices would roughly be the same.

4.2 Effects of changing violation probability of the chance constraints ϵ on the costs

Here, effects of changing violation probability of the chance constraints in the optimization model (for constraints associated with transmission lines capacity) on the total cost has been investigated. As it can be seen in Tables 4.5 and 4.6 that increasing ϵ from 0.01 to 0.05 would have a negligible effect on the energy prices but would change sensitivities more. Now if the values for ϵ changes from 0.05 to 0.1, energy prices and sensitivities would both decrease and the ratio of decrease in both values would be roughly the same, hence we can write

$$\frac{\mathcal{L}_{\text{En}}(\epsilon = 0.05)}{\mathcal{L}_{\text{En}}(\epsilon = 0.1)} \times \frac{\frac{\Delta Cost}{\sigma_L}(\epsilon = 0.05)}{\frac{\Delta Cost}{\sigma_L}(\epsilon = 0.1)} = c \tag{4.1}$$

where c is a scalar and close to zero.

4.3 Effects of changing uncertainty of the buses σ_L on the costs

Here, effects of changing uncertainty in system on energy prices and sensitivities are a point of interest. As it can be seen in Tables 4.7 and 4.8 increasing uncertainty affects sensitivity values significantly but energy prices are not affected a lot. Sensitivities are roughly increasing with the same rate that σ_L is changing.

Table 4.1 Effects of changing traditional generators' limits (P_{max}) on the obtained costs I(Lagrange multipliers for traditional generators limits)

Bus #	**Gen. #**	$P_{max}(bus\#1) = 100\%$		$P_{max}(bus\#1) = 90\%$		$P_{max}(bus\#1) = 110\%$	
		$\mathcal{L}_{\mathrm{m}}$	$\mathcal{L}_{\mathrm{M}}$	$\mathcal{L}_{\mathrm{m}}$	$\mathcal{L}_{\mathrm{M}}$	$\mathcal{L}_{\mathrm{m}}$	$\mathcal{L}_{\mathrm{M}}$
1	1	0	7.6	0	7.6	0	14.6
	2	0	7.6	0	7.6	0	14.6
	3	6.9	0	6.9	0	0	0
	4	6.9	0	6.9	0	0	0
2	5	0	7.5	0	7.5	0	14.5
	6	0	7.5	0	7.5	0	14.5
	7	7.07	0	7.07	0	0	0
	8	7.07	0	7.07	0	0	0
7	9	0	0.26	0	0.89	0	7.6
	10	0	0.26	0	0.89	0	7.6
	11	0	0.26	0	0.89	0	7.6
13	12	0	0.81	0	0.81	0	8.1
	13	0	0.81	0	0.81	0	8.1
	14	0	0.81	0	0.81	0	8.1
15	16	0	1.11	0	1.12	0	11.6
	17	0	1.11	0	1.12	0	11.6
	18	0	1.11	0	1.12	0	11.6
	19	0	1.11	0	1.12	0	11.6
	20	0.49	0	0.49	0	0	0
16	21	0	0	0	0	0	0
18	22	4.50	0	4.50	0	4.33	0
21	23	4.60	0	4.60	0	4.33	0
22	24	8.8	0	8.8	0	8.5	0
	25	8.8	0	8.8	0	8.5	0
	26	8.8	0	8.8	0	8.5	0
	27	8.8	0	8.8	0	8.5	0
	28	8.8	0	8.8	0	8.5	0
	29	8.8	0	8.8	0	8.5	0
	30	8.8	0	8.8	0	8.5	0
23	31	4.2	0	4.2	7.5	0.38	0
	32	4.2	0	4.2	7.5	0.38	0
	33	4.18	0	4.2	7.5	0.38	0

Table 4.2 Effects of changing traditional generators' limits (P_{max}) on the obtained costs I(Energy Price and Sensitivities)

Bus	$P_{max}(bus\#1) = 100\%$		$P_{max}(bus\#1) = 90\%$		$P_{max}(bus\#1) = 110\%$	
#	$\frac{\Delta Cost}{\Delta \sigma_L}$	$\mathcal{L}_{EN}$	$\frac{\Delta Cost}{\Delta \sigma_L}$	$\mathcal{L}_{EN}$	$\frac{\Delta Cost}{\Delta \sigma_L}$	$\mathcal{L}_{EN}$
1	0.1279	17.23	0.1290	17.23	0.1413	10.23
2	0.1174	17.31	0.1183	17.31	0.1298	10.24
3	0.1088	14.86	0.109	14.86	0.1179	10.02
4	0.0936	17.52	0.0943	17.52	0.1035	10.26
5	0.0969	17.73	0.0976	17.73	0.1073	10.28
6	0.2028	18.02	0.2044	18.02	0.2251	10.31
7	0.1801	17.97	0.1815	17.97	0.1998	10.30
8	4.704	17.97	4.7412	17.97	5.2183	10.30
9	0.2289	17.96	0.2307	17.69	0.2534	10.30
10	0.3068	18.24	0.3092	18.24	0.3409	10.28
11	0	20.39	0	20.39	0	10.33
12	0	17.05	0	17.05	0	10.52
13	0.334	17.65	0.3366	17.65	0.3694	10.22
14	1.201	25.15	1.21	25.15	1.3586	10.27
15	1058	10.02	10.5244	10.02	11.96	10.96
16	0.1203	9.53	0.1196	9.53	0.1363	9.58
17	0	9.70	0	9.70	0	9.53
18	0.3789	9.79	0.3768	9.79	0.429	9.55
19	0.1302	11.35	0.1292	11.35	0.1452	9.56
20	0.0679	12.92	0.0676	12.92	0.0742	9.70
21	0	9.86	0	9.86	0	9.84
22	0	9.80	0	9.80	0	9.56
23	0	13.77	0	13.77	0	9.92
24	0	11.84	0	11.84	0	9.74

Table 4.3 Effects of changing traditional generators' limits (P_{max}) on the obtained costs II(Lagrange multipliers for traditional generators limits)

Bus #	**Gen. #**	$P_{max}(bus\#15) = 90\%$ $\mathcal{L}_{\mathrm{m}}$	$P_{max}(bus\#15) = 90\%$ $\mathcal{L}_{\mathrm{M}}$	$P_{max}(bus\#15) = 110\%$ $\mathcal{L}_{\mathrm{m}}$	$P_{max}(bus\#15) = 110\%$ $\mathcal{L}_{\mathrm{M}}$
1	1	0	7.6	0	7.6
	2	0	7.6	0	7.6
	3	6.9	0	6.9	0
	4	6.9	0	6.9	0
2	5	0	7.5	0	7.50
	6	0	7.5	0	7.50
	7	7.07	0	7.07	0
	8	7.07	0	7.07	0
7	9	0	0	0	0.89
	10	0	0	0	0.89
	11	0	0	0	0.89
13	12	0	0.81	0	0.80
	13	0	0.81	0	0.80
	14	0	0.81	0	0.80
15	16	0	1.11	0	1.11
	17	0	1.11	0	1.11
	18	0	1.11	0	1.11
	19	0	1.11	0	1.11
	20	0.49	0	0.49	0
16	21	0	0	0	0
18	22	4.5	0	4.50	0
21	23	4.6	0	4.60	0
22	24	8.8	0	8.8	0
	25	8.8	0	8.8	0
	26	8.8	0	8.8	0
	27	8.8	0	8.8	0
	28	8.8	0	8.8	0
	29	8.8	0	8.8	0
	30	8.8	0	8.8	0
23	31	4.2	0	4.2	7.5
	32	4.2	0	4.2	7.5
	33	4.18	0	4.2	7.5

Table 4.4 Effects of changing traditional generators' limits (P_{max}) on the obtained costs II(Energy Price and Sensitivities)

Bus	$P_{max}(bus\#15) = 90\%$		$P_{max}(bus\#15) = 110\%$	
#	$\frac{\Delta Cost}{\Delta \sigma_L}$	$\mathcal{L}_{EN}$	$\frac{\Delta Cost}{\Delta \sigma_L}$	$\mathcal{L}_{EN}$
1	0.1271	17.23	0.1288	17.23
2	0.1167	17.31	0.1182	17.31
3	0.1088	14.86	0.1089	14.86
4	0.0930	17.52	0.0942	17.52
5	0.0962	17.73	0.0975	17.73
6	0.2013	18.02	0.2042	18.02
7	0.1788	17.97	0.1814	17.97
8	4.674	17.97	4.7376	17.97
9	0.2273	17.96	0.2305	17.69
10	0.3046	18.24	0.309	18.24
11	0	20.39	0	20.39
12	0	17.05	0	17.05
13	0.331	17.65	0.3363	17.65
14	1.192	25.15	1.21	25.15
15	10.66	10.02	10.5154	10.02
16	0.1210	9.53	0.1195	9.53
17	0	9.70	0	9.70
18	0.3814	9.79	0.3765	9.79
19	0.1313	11.35	0.1291	11.35
20	0.0685	12.92	0.0674	12.92
21	0	9.86	0	9.86
22	0	9.80	0	9.80
23	0	13.77	0	13.77
24	0	11.84	0	11.84

Table 4.5 Effects of changing violation probability of the chance constraints ϵ on the costs(Lagrange multipliers for traditional generators limits)

Bus	**Gen.**	$\epsilon = 0.05$		$\epsilon = 0.01$		$\epsilon = 0.1$	
#	**#**	$\mathcal{L}_{\rm m}$	$\mathcal{L}_{\rm M}$	$\mathcal{L}_{\rm m}$	$\mathcal{L}_{\rm M}$	$\mathcal{L}_{\rm m}$	$\mathcal{L}_{\rm M}$
1	1	0	7.6	0	7.6	0	14.6
	2	0	7.6	0	7.6	0	14.6
	3	6.9	0	6.9	0	0	0
	4	6.9	0	6.9	0	0	0
2	5	0	7.5	0	7.5	0	14.5
	6	0	7.5	0	7.5	0	14.5
	7	7.07	0	7.07	0	0	0
	8	7.07	0	7.07	0	0	0
7	9	0	0	0	0.89	0	7.6
	10	0	0	0	0.89	0	7.6
	11	0	0	0	0.89	0	7.6
13	12	0	0.8	0	0.81	0	8.2
	13	0	0.8	0	0.81	0	8.2
	14	0	0.8	0	0.81	0	8.2
15	16	0	1.11	0	1.12	0	11.6
	17	0	1.11	0	1.12	0	11.6
	18	0	1.11	0	1.12	0	11.6
	19	0	1.11	0	1.12	0	11.6
	20	0.49	0	0.49	0	0	0
16	21	0	0	0	0	0	0
18	22	4.5	0	4.5	0	4.33	0
21	23	4.6	0	4.6	0	4.33	0
22	24	8.8	0	8.8	0	8.5	0
	25	8.8	0	8.8	0	8.5	0
	26	8.8	0	8.8	0	8.5	0
	27	8.8	0	8.8	0	8.5	0
	28	8.8	0	8.8	0	8.5	0
	29	8.8	0	8.8	0	8.5	0
	30	8.8	0	8.8	0	8.5	0
23	31	4.2	0	4.2	7.5	0.38	0
	32	4.2	0	4.2	7.5	0.38	0
	33	4.18	0	4.2	7.5	0.38	0

Table 4.6 Effects of changing violation probability of the chance constraints ϵ on the costs(Energy Price and Sensitivities)

Bus	$\epsilon = 0.05$		$\epsilon = 0.01$		$\epsilon = 0.1$	
#	$\frac{\Delta Cost}{\Delta \sigma_L}$	$\mathcal{L}_{EN}$	$\frac{\Delta Cost}{\Delta \sigma_L}$	$\mathcal{L}_{EN}$	$\frac{\Delta Cost}{\Delta \sigma_L}$	$\mathcal{L}_{EN}$
1	0.1279	17.23	0.1809	17.23	0.0796	10.23
2	0.1174	17.31	0.1661	17.31	0.0729	10.24
3	0.1088	14.86	0.1539	14.86	0.0724	10.02
4	0.0936	17.52	0.1324	17.52	0.0579	10.26
5	0.0969	17.73	0.137	17.73	0.0597	10.28
6	0.2028	18.02	0.2868	18.02	0.1243	10.31
7	0.1801	17.97	0.2547	17.97	0.1106	10.30
8	4.704	17.97	6.6533	17.97	2.8886	10.30
9	0.2289	17.96	0.3237	17.69	0.1414	10.30
10	0.3068	18.24	0.4339	18.24	0.1874	10.28
11	0	20.39	0	20.39	0	10.33
12	0	17.05	0	17.05	0	10.52
13	0.334	17.65	0.4725	17.65	0.2069	10.22
14	1.201	25.15	1.69	25.15	0.7035	10.27
15	10.58	10.02	14.97	10.02	6.64	10.96
16	0.1203	9.53	0.1796	9.53	0.0747	9.58
17	0	9.70	0	9.70	0	9.53
18	0.3789	9.79	0.2359	9.79	0.236	9.53
19	0.1302	11.35	0.1841	11.35	0.0848	9.56
20	0.0679	12.92	0.0961	12.92	0.046	9.70
21	0	9.86	0	9.86	0	9.84
22	0	9.80	0	9.80	0	9.56
23	0	13.77	0	13.77	0	9.92
24	0	11.84	0	11.84	0	9.74

Table 4.7 Effects of changing uncertainty of the buses σ_L on the costs (Lagrange multipliers for traditional generators limits)

Bus	**Gen.**	$\sigma_L = 1\%$		$\sigma_L = 5\%$		$\sigma_L = 10\%$	
#	**#**	$\mathcal{L}_m$	$\mathcal{L}_M$	$\mathcal{L}_m$	$\mathcal{L}_M$	$\mathcal{L}_m$	$\mathcal{L}_M$
1	1	0	7.6	0	7.6	0	7.6
	2	0	7.6	0	7.6	0	14.6
	3	6.9	0	6.9	0	6.9	0
	4	6.9	0	6.9	0	6.9	0
2	5	0	7.5	0	7.5	0	14.5
	6	0	7.5	0	7.5	0	14.5
	7	7.07	0	7.07	0	7.07	0
	8	7.07	0	7.07	0	7.07	0
7	9	0	0.26	0	0.89	0	7.6
	10	0	0.26	0	0.89	0	7.6
	11	0	0.26	0	0.89	0	7.6
13	12	0	0.81	0	0.81	0	8.1
	13	0	0.81	0	0.81	0	8.1
	14	0	0.81	0	0.81	0	8.1
15	16	0	1.11	0	1.12	0	11.1
	17	0	1.11	0	1.12	0	11.1
	18	0	1.11	0	1.12	0	11.1
	19	0	1.11	0	1.12	0	11.1
	20	0.49	0	0.49	0	0.49	0
16	21	0	0	0	0	0	0
18	22	4.5	0	4.5	0	4.50	0
21	23	4.6	0	4.6	0	4.33	0
22	24	8.8	0	8.8	0	8.8	0
	25	8.8	0	8.8	0	8.8	0
	26	8.8	0	8.8	0	8.8	0
	27	8.8	0	8.8	0	8.8	0
	28	8.8	0	8.8	0	8.8	0
	29	8.8	0	8.8	0	8.8	0
	30	8.8	0	8.8	0	8.8	0
23	31	4.2	0	4.2	7.5	4.23	0
	32	4.2	0	4.2	7.5	4.23	0
	33	4.18	0	4.2	7.5	4.18	0

Table 4.8 Effects of changing uncertainty of the buses σ_L on the costs (Energy Price and Sensitivities)

Bus	$\sigma_L = 1\%$		$\sigma_L = 5\%$		$\sigma_L = 10\%$	
#	$\frac{\Delta Cost}{\Delta \sigma_L}$	$\mathcal{L}_{EN}$	$\frac{\Delta Cost}{\Delta \sigma_L}$	$\mathcal{L}_{EN}$	$\frac{\Delta Cost}{\Delta \sigma_L}$	$\mathcal{L}_{EN}$
1	0.1809	17.23	0.8077	17.23	1.335	17.23
2	0.1661	17.31	0.7414	17.31	1.225	17.31
3	0.1539	14.86	0.6962	14.86	1.179	14.86
4	0.1324	17.52	0.5904	17.52	0.9748	17.52
5	0.137	17.73	0.6105	17.73	1.006	17.73
6	0.2868	18.02	1.2767	18.02	2.1002	18.02
7	0.2547	17.97	1.1344	17.97	1.8675	17.97
8	6.653	17.97	6.2602	17.97	5.4964	17.97
9	0.3237	17.96	1.4435	17.69	2.3815	17.69
10	0.4339	18.24	1.9305	18.24	3.1724	18.24
11	0	20.39	0	20.39	0	20.39
12	0	17.05	0	17.05	0	17.05
13	0.472	17.65	2.1076	17.65	3.4801	17.65
14	1.698	25.15	7.4986	25.15	12.521	25.15
15	14.97	10.02	14.149	10.02	13.26	10.02
16	0.1701	9.53	0.7593	9.53	1.255	9.53
17	0	9.70	0	9.70	0	9.70
18	0.5359	9.79	2.394	9.79	3.969	9.79
19	0.1841	11.35	0.8295	11.35	1.394	11.35
20	0.0961	12.92	0.4364	12.92	0.7442	12.92
21	0	9.86	0	9.86	0	9.86
22	0	9.80	0	9.80	0	9.80
23	0	13.77	0	13.77	0	13.77
26	0	11.84	0	11.84	0	11.84

Chapter 5

Conclusion and Future Work

We have introduced a method for locational pricing of variability of power injections and presented an example with wind generators and loads. It is computed as a sensitivity of production cost to a measure of variability for generators and loads. In this thesis we use the statistical standard deviation of power injection as this measure. The price could be used for pricing regulation and thus would equitably allocate charges to those generators and loads with variable injections. We suggest that such a charging scheme may provide incentives for load energy storage to reduce variability, and hence the price serves as means to value energy storage by location.

More research is needed to consider additional examples to fully assess the potential impact of a location regulation price. Additional technical work can rigorously relate the prices to binding constraints and should also consider other measures for variability.

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