A Probabilistic Approach to Security Costs in Competitive Electricity Markets

by

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Abstract

This thesis introduces a novel approach to security cost analysis in competitive electricity markets. The complexity of modern power systems compels us to take a sophisticated probabilistic approach to system operation to assess risk and associated costs. Current risk mitigation techniques are predominantly deterministic, and may lead to an inaccurate cost assessment.

In this thesis, concepts from reliability, risk analysis and voltage stability theory are applied to determine the total cost of maintaining system security. Probability theory facilitates an assessment of the uncertainty of transmission contingencies occurring, while voltage stability margins in conjunction with bus voltage and thermal limits makes it possible to determine the risk of system security violations.

Once the cost of maintaining the system security has been ascertained, it is possible to distribute the security cost among the participants in the system. Although it is shown that the Available Transfer Capability (ATC) is not a good security index for curbing transactions, it is valuable for determining the impact of transactions on the system transfer capability. This transaction impact evaluation applies sensitivity analysis of the ATC to all transactions in the system. This analysis includes all market participants.

The techniques described in this thesis are applied to two different systems: a six-bus test system and a 129-bus model of the Italian HV transmission system. The results for the sample systems show that operating a system at the ATC does not eliminate the risk of a security limit violation. Furthermore, these results show that in some cases the associated security costs are sufficiently small that it may be

reasonable to allow transaction levels to exceed the ATC index. The security costs for each system are then distributed among the participants and are shown to be reasonable vis-á-vis the total value of the participants' transactions.

Acknowledgments

Firstly, I would like to thank my supervisor, Dr. Claudio A. Cañizares for his support throughout my time as a graduate student here. His guidance and encouragement have kept me focused on producing the best research possible.

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Chapter 1

Introduction

1.1 Motivation

Traditionally, the electric power industry was managed by large utilities who owned all aspects of the power supply, *i.e.*, generation, transmission, and distribution. These vertically integrated utilities were heavily regulated by the government, and were often granted monopoly status in return for servicing all customers in their designated area.

The main objective of these utilities was to minimize operating costs while satisfying all of the constraints in the system. The government took a central role in regulating the activities and rates passed on to consumers, and this system worked well for many years. However, electricity rates began to rise with fuel prices in the late seventies and the public began to question the economic framework of the electric industry [1].

Supporters of competitive markets argue that competition is a more effective method for improving efficiency. For example, in the late seventies, Chile deregulated its electric power system. In the period from 1986 to 1996, transmission losses reduced from approximately 21% to around 8%. Moreover, Chile's largest generator (Endesa) increased production from just under 7000 GWh/year to approximately 13000GWh/year between 1989 and 1996, but also managed to reduce the number of employees by approximately 36% during this same period [2]. On the other hand, critics of the deregulation process point to gaming activities and price spikes in California as an example of why deregulation is not a viable option in the electric industry. The volatility of prices often associated with electricity markets is not common in the traditional centralized structure.

It is clear that the introduction of competitive markets has fundamentally altered the economics of the industry. In some jurisdictions the result has been less expensive power, while in others prices have increased. However, it is widely accepted that these commodity markets have forced the industry to focus on economic considerations. From an engineering standpoint, the effect of this change is additional pressure to reduce security margins thus increasing profitability.

1.1.1 System Security

Despite some of the economic benefits from the introduction of competition, there is also increased technical complexity to maintain these systems. The traditionally "central" security coordination mechanisms are being replaced by new, independent organizations typically referred to as the independent system operator (ISO).

Furthermore, the desire to minimize costs has translated into a desire to maximize the use of existing infrastructure and avoid capital expenditures. The result of this trend is a steady deterioration in security margins that were once built into the system. By pushing the envelope on existing capacity, issues relating to stability have begun to bubble to the surface, a large number of which are voltage stability issues. For example, the blackout of August 14, 2003 was the result of a catastrophic loss of voltage stability which ended up costing the U.S. economy $6.4 billion [3]. This event is believed to have been caused by a series of transmission line contingencies and reactive power shortages [4]. Ultimately, voltage stability was lost and the system collapsed. Although the investigation of this event is ongoing, it highlights the importance of understanding the security limits in a given system, and the risks associated with operating the system at given loading levels. This thesis presents an analysis of the risk of security limit violations when operating a system in a market environment, and it includes voltage stability limits, as well as bus voltage limits and thermal limits.

1.1.2 Risk Analysis

To meet the increasing complexity of power system operations, it is essential that new and sophisticated methods be introduced to help operators and planners make decisions. In many fields of study, risk evaluation is a mature discipline. In industries such as insurance and finance, risk is the cornerstone of the decision making process. However, it is also beginning to receive attention in the field of power system analysis.

Power systems are traditionally operated with the underlying assumption that the avoidance of security limit violations is among the highest of priorities. For this reason, a risk analysis of security has been viewed as unnecessary because the ultimate goal is to make the risk as close to zero as possible. As competitive markets for power have emerged, this zero-risk mandate is not sustainable. It is no longer acceptable to reduce risk at any cost because people are not willing to pay the corresponding high prices for power.

Deterministic methods are still predominantly used for security evaluation in most deregulated systems. It is *assumed* that adhering to the limits defined by these methods will facilitate an acceptably low level of risk. However, since these methods are deterministic, they do not quantify uncertainties in the system. Therefore, by using deterministic methods it can be assumed that risk is low, but it is not possible to determine how low it actually is. It is essential that a comprehensive method for evaluating the risks present in a system be developed. The goal of this thesis is to facilitate this process by integrating the risk of security limit violations into a security cost for market participants.

1.1.3 Pricing Security

Transmission security problems manifest themselves as transmission congestion. In other words, it may not be possible to allow additional transactions to take place because it would result in a violation of bus voltage, thermal or voltage stability limits [5]. To account for congestion in a market-based system, it is necessary to be able to price security. For example, optimal power flow (OPF) techniques have been studied because they introduce locational marginal prices (LMP) and attempt to find an optimal solution [6]. However, the solution methods are not necessarily transparent to the participants in a market and there may be convergence problems [7]. Furthermore, accounting for uncertainty in this framework would be a difficult task and would further complicate the solution process. The methods presented in this thesis implement a uniform pricing model, with a security cost as an "adjustment." These methods offer simplicity and incorporate the risk of transmission contingencies, with the obvious drawback that they are not optimal.

1.2 Literature Review

In competitive markets, techniques for maintaining security have received a lot of attention. In [8], contingency pricing incentives are explored for maintaining security. OPF techniques can also be used to improve system security as shown in [6].

The authors of [9] justify the use of risk-based security assessment in modern system operations, and the importance of including uncertainty in the decision making process of power system operations is described. Risk-based security assessment techniques are shown in [10], [11], and [12]; these methods incorporate operating and contingency uncertainty in the analysis. Firstly, operating condition uncertainty in loading is managed by assuming a normal distribution, using the forecasted value as the mean. Similarly, operating condition uncertainty in parameters such as load distribution factors and generation participation factors are assumed to be multi-variate normal (MVN) distributed. Secondly, contingency uncertainty is assumed to follow the Poisson distribution. This thesis uses similar techniques for handling contingency uncertainty as those presented in [11] to develop the framework for security costs. Operating condition uncertainty is beyond the scope of this thesis, since it is assumed that the variance of values submitted to the operator will be sufficiently low. Incorporating only contingency uncertainty also simplifies the security cost assessment, which is desirable for participants in commodity markets where transparency is important [13].

The available transfer capability (ATC) is often used to evaluate the remaining transfer capability of power "corridors" [14], but the definition in [15] does not restrict its use. In this thesis, it is treated as a system index used in the sensitivity analysis to evaluate the effect of transactions on the system's transfer capability [16]. The ATC calculation is based on security limits including bus voltage and thermal limits. The ATC calculation also incorporates voltage stability limits which are shown in [17] to be essential for preserving system security. These limits are evaluated using continuation power flow (CPF) techniques, which are shown in [18] to be effective at evaluating limits used in the ATC evaluation.

A "take-risk" strategy is presented in [19] and [20] to assign security costs to a system. The framework takes a probabilistic view of the ATC to better evaluate the effect of market transactions on system security. It also uses the sensitivity of the ATC to market transactions to distribute the security costs to the market participants.

Several novel concepts are introduced in this thesis. The security cost evaluation introduced in [19] is extended by using the Poisson distribution and reliability data to account for the uncertainty of transmission contingencies. Additionally, a cost function is implemented that accounts for different costs depending on the type of security limit violation. A similar approach to the method presented in [19] for transaction impact (TI) evaluation is used, however in this thesis, the effects of *all* participants in the system are included, not just those participating in the market. Furthermore, the examples presented in this thesis demonstrate that the ATC is an effective tool for distributing security costs to participants; however, when used as a security limit, it is shown that the ATC does not accurately reflect risks in system operation.

1.3 Outline

This thesis is organized as follows: Chapter 2 outlines the TI methodology. This chapter reviews the ATC concept and basic voltage stability concepts, both of which are necessary to implement the TI technique. Sensitivity analysis is then implemented to determine the impact of transactions on the ATC. Chapter 3 discusses the security cost analysis technique. Reliability and probability concepts used in the security cost assessment are explained, and the calculation procedure is outlined. In Chapter 4, the proposed security cost analysis methods are implemented on a 6-bus system and a 129-bus model of the Italian HV transmission system. Finally, in Chapter 5 the main contributions of the thesis are discussed and suggestions for future research are given.

Chapter 2

Transaction Impact Analysis

This chapter discusses a method for determining the impact of transactions on the transfer capability of power systems. Fundamental concepts in voltage stability analysis and CPF techniques are reviewed since they form the basis for the analysis. As well, the ATC index is discussed in the context of TI analysis. Finally, the TI calculation is described.

2.1 Voltage Stability

2.1.1 Loading Margin

To lay the foundation for voltage stability analysis, it is necessary to define system loading margin and its use in this thesis. For a particular operating point, the amount of additional load in a specific pattern of load increase that would cause a voltage collapse is called the loading margin to voltage collapse [21]. In this thesis, loading margin is also defined for bus voltage limits and thermal limits. System load is the parameter that varies so that the system PV curve can be drawn, and the loading margin is then the maximum amount of additional system load that can be sustained before a system limit is reached. This concept is important in the ATC calculation discussed later.

Mathematically, the loading margin for a system can be stated as:

$$L = L_{lim} - L_0 \tag{2.1}$$

where L_{lim} is the maximum loading of the system at a given limit, and L_0 is the base or current loading. In Figure 2.1, the loading margins are identified for a sample system PV curve. In this figure, loading margins are shown for three limit types: bus voltage (V_{lim}), thermal (I_{lim}), and voltage stability (S_{lim}). In this example, the bus voltage limits "dominate" because they occur at the lowest loading factor, but this may be different for other systems.

The advantage of using the loading margin is that it is possible to evaluate the sensitivity of it to any arbitrary parameter [22]. This characteristic is necessary for the TI calculation discussed later.

2.1.2 Stability Concepts

Power systems are complex engineering systems which are typically modeled by a highly nonlinear set of equations. In stability analysis, it is common to study power systems with a set of differential equations of the following form:

$$\dot{x} = f(x) \tag{2.2}$$

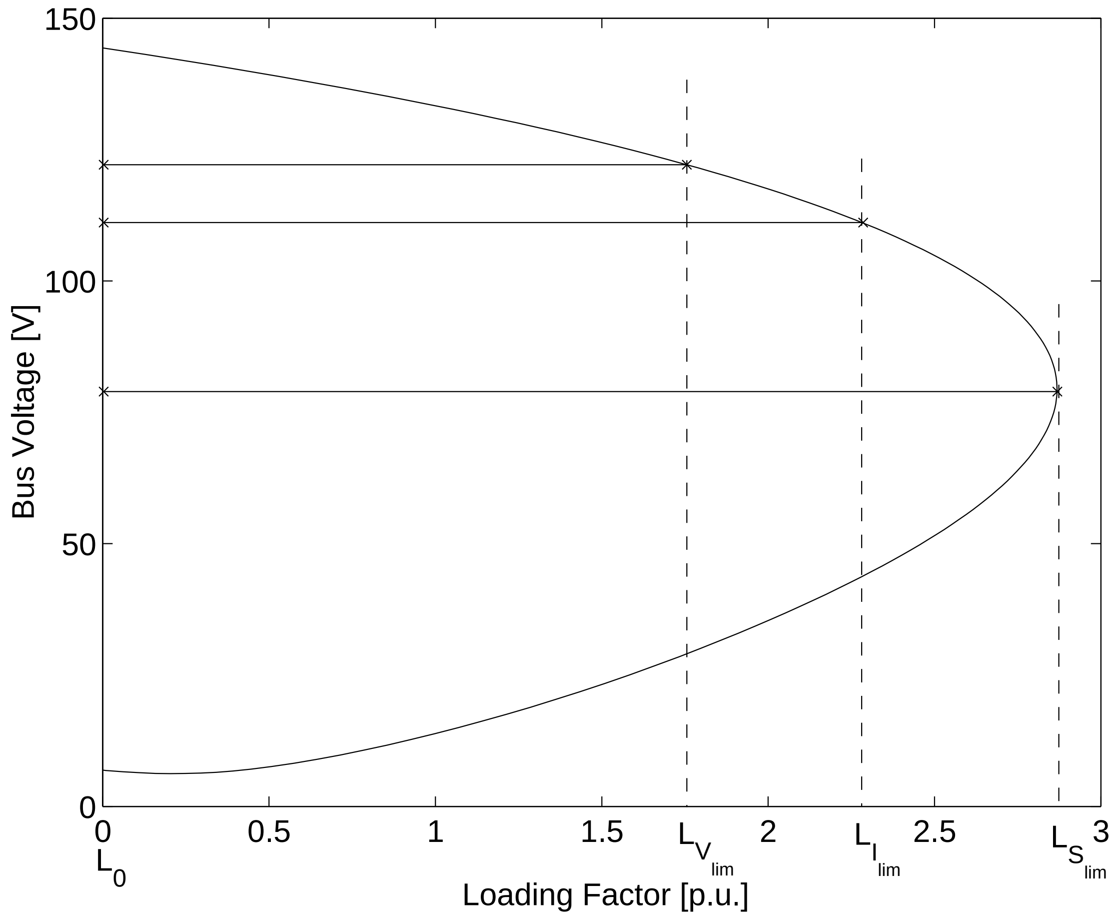

Figure 2.1: Loading margins for a sample system.

where an equilibrium point, x_0, is defined by:

$$f(x_0) = 0 \tag{2.3}$$

In a given system, there can be many equilibrium points. However, power system operators are interested in *stable* equilibrium points, or operating points. A stable equilibrium point is defined as [21]:

> An operating point of a power system is *small disturbance stable* if, following any disturbance, the power system state returns to the identical or close to the pre-disturbance operating point.

Upon identifying the stable equilibrium points, it is then important to understand *how* stable each operating point is. In other words, to what extent can a system be perturbed before the system moves away from a stable equilibrium point. One method for evaluating the stability region is an "energy" analysis. A common analogy used for describing this stability region is that of a ball at the bottom of a valley where it is at a stable equilibrium point. If a disturbance has enough energy to displace the ball over the walls of the valley, then the system will become unstable. Similarly in a power system, if a disturbance has enough energy to move the system far enough from a stable equilibrium point, then it may become unstable [23].

It is possible that stability may be lost if, assuming slowly varying parameters, a stable equilibrium point becomes an unstable equilibrium point. Under the same conditions, it is also possible that stability may be lost due to the "disappearance" of a stable equilibrium point. These events are referred to as bifurcations, and may be followed by a collapse in system voltages. Bifurcations that occur due to the disappearance of stable equilibrium points are the focus of the voltage stability analysis presented in this thesis.

In bifurcation theory, it is assumed that power system parameters change slowly, with the following differential algebraic equations used to model the system:

$$\begin{aligned} \dot{x} &= f(x, y, p, \lambda) \\ 0 &= g(x, y, p, \lambda) \end{aligned} \tag{2.4}$$

where $x \in \mathbb{R}^n$ represents the system state variables such as generator angles; $y \in \mathbb{R}^m$ represents the system algebraic variables such as load voltages. Controllable system parameters are represented by $p \in \mathbb{R}^k$ which may include tap settings and reference voltages for compensation; $\lambda \in \mathbb{R}^l$ (typically $l = 1$) represents uncontrollable parameters or bifurcation parameters which is usually a scalar representing system loading. The nonlinear functions $f : \mathbb{R}^n \times \mathbb{R}^m \times \mathbb{R}^k \times \mathbb{R}^l \mapsto \mathbb{R}^n$ and $g : \mathbb{R}^n \times \mathbb{R}^m \times \mathbb{R}^k \times \mathbb{R}^l \mapsto \mathbb{R}^m$ typically represent system equations such as real and reactive power injections.

Equilibrium states $z_0 = (x_0, y_0)$ for parameters p_0 and λ_0 are the solution to (2.4):

$$\begin{aligned} f(x_0, y_0, p_0, \lambda_0) &= 0 \\ g(x_0, y_0, p_0, \lambda_0) &= 0 \end{aligned} \tag{2.5}$$

which can be expressed compactly as:

$$F(z_0, p_0, \lambda_0) = 0 \tag{2.6}$$

Common types of bifurcations seen in power systems are saddle-node bifurcations (SNB), limit-induced bifurcations (LIB) and Hopf bifurcations. SNBs and some LIBs are characterized by the disappearance of equilibrium points, whereas Hopf bifurcations are characterized by a stable equilibrium point transforming into an unstable equilibrium point. Only SNBs and LIBs are considered here; Hopf bifurcations are beyond the scope of this thesis.

Saddle Node Bifurcations

Saddle node bifurcations are known to be a common cause of voltage collapse [21]. They are indicated by the coalescence of a pair of equilibrium points (one is unstable), which subsequently disappear as the bifurcation parameter changes. These events lead to changes in the stability regions and can cause voltage collapse in power systems. A SNB is characterized by the steady state Jacobian, $D_zF(z_0, p_0, \lambda_0)$, having a simple and unique zero eigenvalue, and associated nonzero right eigenvector v and left eigenvector w. These conditions are described by the following equations for the right eigenvector [24]:

$$\begin{aligned} F(z, p, \lambda) &= 0 \\ D_zF(z, p, \lambda)v &= 0 \\ \|v\| &\neq 0 \end{aligned} \tag{2.7}$$

and for the left eigenvector:

$$
\begin{aligned}
F(z,p,\lambda) &= 0 \\
D_z^T F(z,p,\lambda)w &= 0 \\
\|w\| &\neq 0
\end{aligned}
\tag{2.8}
$$

where the SNB is the solution to (2.7) and (2.8).

Limit-induced Bifurcations

A LIB may be associated with control limits such as the reactive power output of generators or the tap limits on tap-changing transformers [21]. This phenomenon is characterized by a "jump" in the eigenvalues of the system Jacobian at the bifurcation point, and *may* lead to voltage collapse.

The point at which a LIB occurs leads to a change in the system model. For example, a generator that is modeled as a PV bus turns into a PQ bus at a LIB due to reactive power limits. In this case, voltage becomes a state variable and reactive power becomes a constant. The sample trajectory $F(z)$ shown in Figure 2.2 may change after a LIB is reached to form the new system, $\widetilde{F}(z)$. This new system may or may not be stable. If the equilibrium point disappears at the LIB resulting in a "catastrophic" bifurcation (loss of stability), the bifurcation is referred to as a saddle limit-induced bifurcation (SLIB) which is somewhat similar to a SNB [25]. Typically, only SLIBs are of interest in voltage stability analysis.

In power systems, the equilibrium points considered are the solutions to the power flow equations used. Therefore, this analysis is only applicable to certain

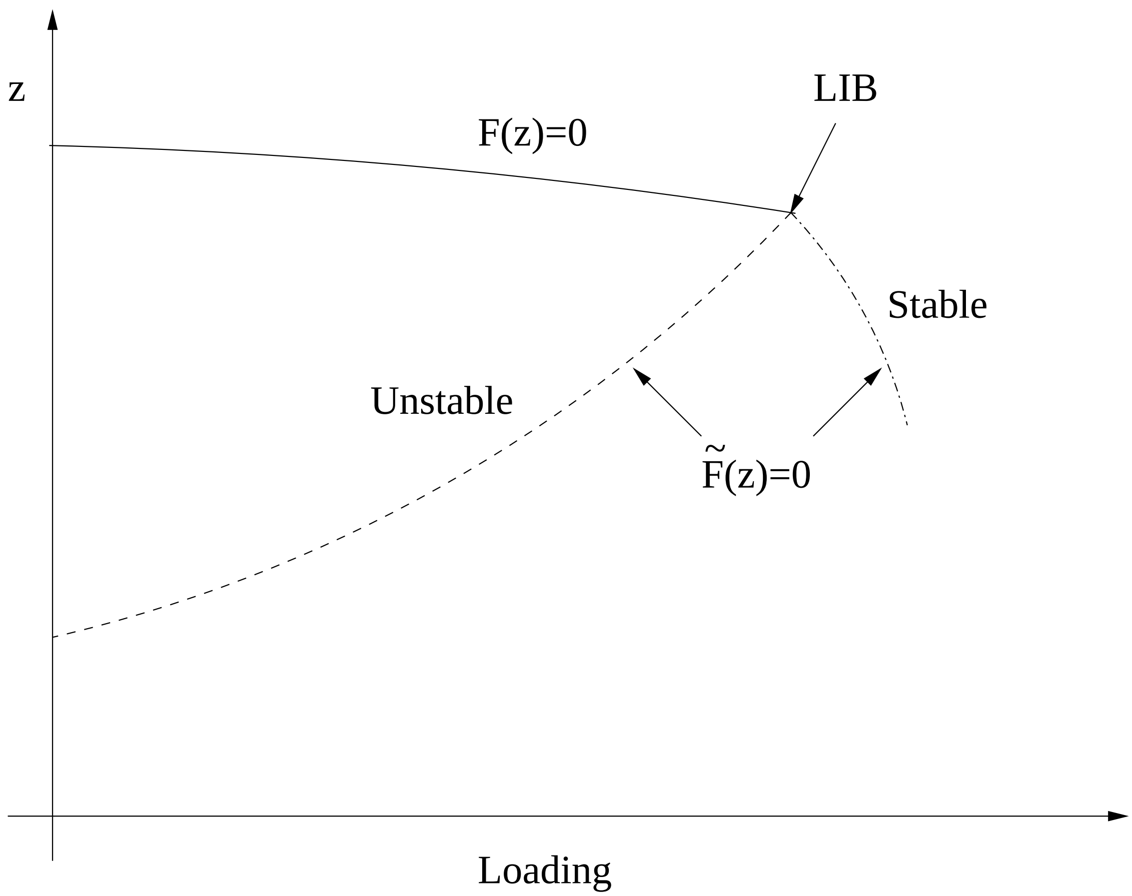

Figure 2.2: Possible trajectories for a system after a LIB.

system models. Understanding the behavior of these equilibrium points by identifying bifurcations in a given power system facilitates an understanding of the voltage stability limits. However, locating these points is not a trivial task. Recall that bifurcations assume a slowly changing bifurcation parameter, usually loading. Furthermore, the steady state Jacobian is singular at a SNB, for example, making the solution of the nonlinear system difficult to obtain at this point. The CPF technique introduced below is commonly used to perform the voltage stability evaluation.

2.1.3 Continuation Power Flow

CPF is an established method for calculating the maximum loadability of a system [21], [24], and it is typically used to find the loading margin for a system as illustrated in Figure 2.1. The method assumes that the variations in active and reactive power parameters are the main contributors that lead the system power flow Jacobian to a singularity and thus voltage collapse. The technique introduces a scalar parameter λ which is incremented in discrete steps; the power flow solution is found at each stage. The continuation method involves a predictor-corrector algorithm to facilitate convergence of the solution process.

Mathematically, the basic system power flow equations are represented by the following set of non-linear equations:

$$\begin{aligned} P_{Gi} - P_{Li} - \sum_{j=1}^{N} V_i V_j [G_{ij} cos(\delta_i - \delta_j) + B_{ij} sin(\delta_i - \delta_j)] &= 0 \\ Q_{Gi} - Q_{Li} - \sum_{j=1}^{N} V_i V_j [G_{ij} sin(\delta_i - \delta_j) - B_{ij} cos(\delta_i - \delta_j)] &= 0 \end{aligned} \tag{2.9}$$

where P_G and Q_G represent the real and reactive generation bus power injections at bus i; P_L and Q_L represent the real and reactive load bus power injections; G and B are the real and imaginary components of the bus admittance matrix; V and δ represent the bus voltages and angles. If constant load models are assumed and allowed to change, then the changes in bus load powers as a function of λ are as follows:

$$\begin{aligned} P_{L_i} &= P_{L_{0i}} + \lambda \Delta P_{L_i} \\ Q_{L_i} &= Q_{L_{0i}} + \lambda \Delta Q_{L_i} \end{aligned} \tag{2.10}$$

where P_0 and Q_0 are the base real and reactive powers respectively at bus i; ΔP and ΔQ form the vector of direction of load change which includes the effects of all transactions[1] in the system.

Generators are assumed to meet the load requirements according to their scheduled change ΔP_G in response to market conditions, a "base" power, and a participation factor k_G which represents a distributed slack bus for the purpose of distributing losses:

$$P_{G_i} = P_{G_{0i}} + \Delta P_{G_i}(\lambda + k_{G_i}) \tag{2.11}$$

[1] In this thesis, the term "transactions" refers to all bids, contracts, and other existing commitments in the system

The basic CPF procedure is illustrated in Figure 2.3. This procedure permits the evaluation of a full PV profile for a system where the term “limit” in the decision stage means a bus voltage limit, thermal limit, SNB or SLIB.

Predictor Stage

In the predictor stage, the CPF technique attempts to guess the solution to the next increment of λ. This prediction is based on the tangent vector to the solution path evaluated at the current solution. The direction vector, Δz_1, at an equilibrium point (z_1, λ_1) can then be found. Given that $F(z_1, \lambda_1) = 0$, then:

$$\frac{dF}{d\lambda}(z_1, \lambda_1) = D_z F(z_1, \lambda_1) \left.\frac{dz}{d\lambda}\right|_1 + \left.\frac{\partial F}{\partial \lambda}\right|_1 = 0 \tag{2.12}$$

$$\left.\frac{dz}{d\lambda}\right|_1 = -[D_z F|_1]^{-1} \left.\frac{\partial F}{\partial \lambda}\right|_1 \tag{2.13}$$

Then, given a positive scalar, α:

$$\Delta\lambda_1 = \frac{\alpha}{\|dz/d\lambda|_1\|} \tag{2.14}$$

with the direction vector being defined as:

$$\Delta z_1 = \Delta\lambda_1 \left.\frac{dz}{d\lambda}\right|_1 \tag{2.15}$$

The predicted solution for the next iteration is then $(z_2', \lambda_2') = (z_1 + \Delta z_1, \lambda_1 + \Delta\lambda_1)$. It is possible that the complete solution process may take too long if α is chosen too small. Similarly, if α is too large, there may be convergence problems. Therefore, it is common to set $\alpha = 1$, and then implement a step-cutting algorithm to reduce the step lengths as the process approaches the bifurcation point [21].

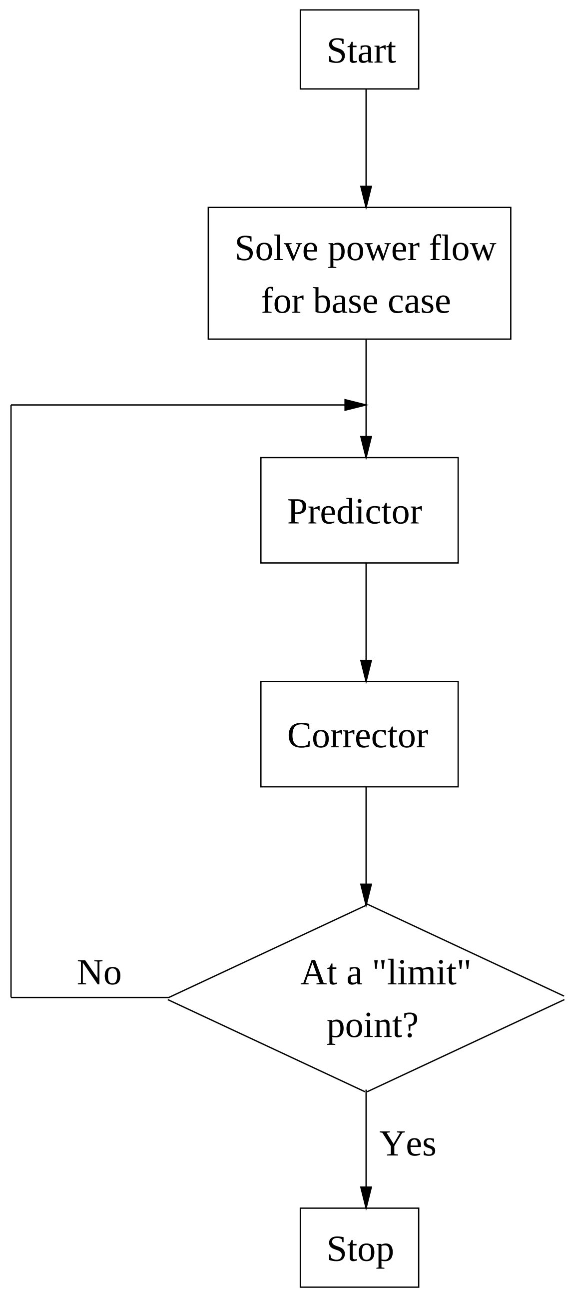

Figure 2.3: CPF procedure to find the loading margin.

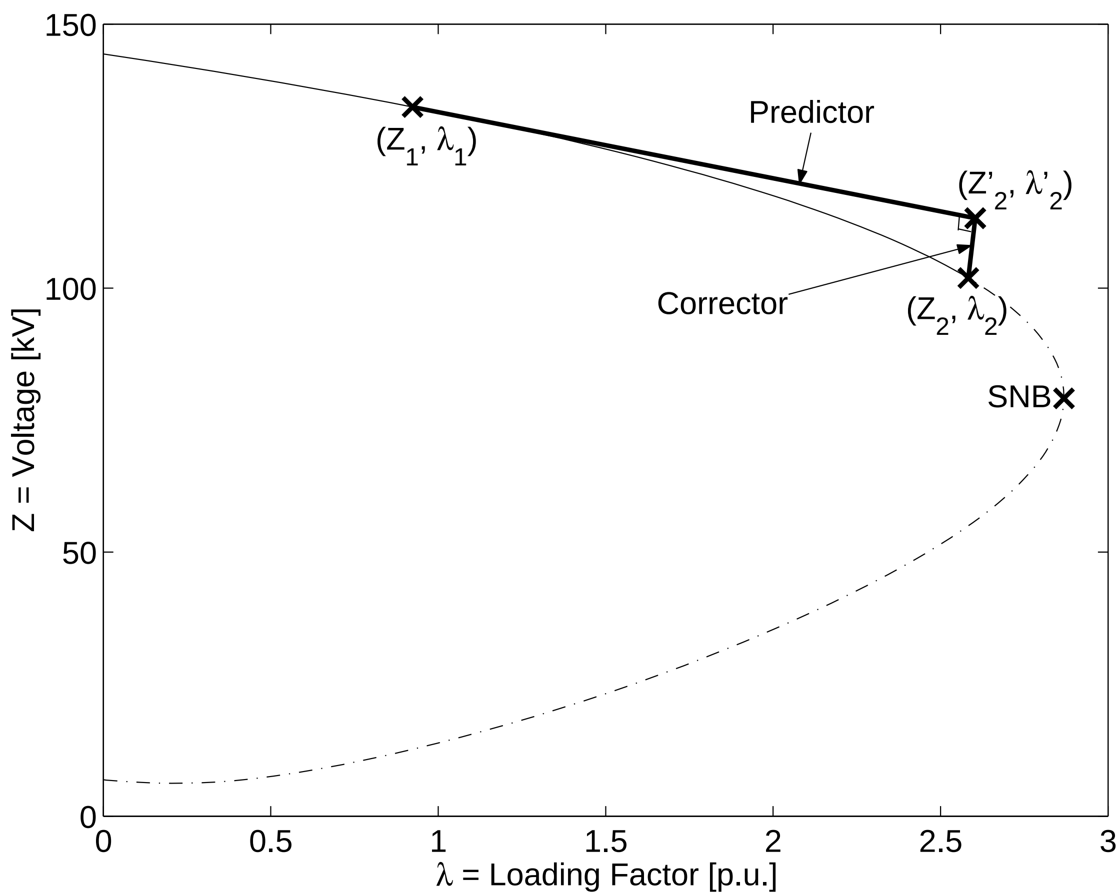

Figure 2.4: Predictor-corrector stages in the CPF.

Corrector Stage

The purpose of the corrector stage is to calculate (z_2, λ_2) from (z_2', λ_2'). In this stage, the original system of power flow equations is augmented, in one of the techniques used, with a perpendicular vector to the tangent that intersects the PV curve:

$$F(z, \lambda) = 0 \tag{2.16}$$

$$\Delta z_1^T (z - z_2') + \Delta \lambda_1^T (\lambda - \lambda_2') = 0 \tag{2.17}$$

where (2.16) is the original system of power flow equations, and (2.17) is the perpendicular vector that intersects the PV curve. The solution to this system of equations is (z_2, λ_2). The CPF procedure is illustrated in Figure 2.4 for a SNB; both the predictor and corrector stages are indicated.

At certain stages in the CPF procedure, it is usually necessary to use "step-cutting" to find a solution point. Thus if the length of Δz_1 in the predictor stage is too "long", then the perpendicular corrector may not intersect the PV curve. In such cases, it is necessary to systematically reduce α in (2.14) until a solution can be found. This technique makes it possible to detect the SNB or SLIB and trace the full PV curve.

2.2 Available Transfer Capability (ATC)

2.2.1 ATC Definition

The ATC is defined as "a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses" [15]. This index is often used as a measure of additional power that can be securely transferred by a transmission network. This concept is different from the overall transmission capacity that is theoretically possible in a given system.

The ability of a system to reliably transfer power is constrained by one or more of the following limits: thermal, bus voltage and stability [15]. Thermal limits reflect the current carrying ability of the transmission network before overheating occurs. Bus voltage limits put lower and upper bounds on the bus voltages acceptable in the system before damage to equipment occurs, while stability limits indicate the ability of the system to withstand disturbances. To evaluate the ATC, it is also necessary to consider the effect of contingencies on the limits of the system. The contingency analysis techniques used in this thesis are discussed below.

Rigorous ATC calculation procedures require costly time-domain simulations that are often impractical to implement, especially in light of the fact that multiple system conditions and contingencies must be considered. Furthermore, these procedures don't readily facilitate sensitivity information that is necessary in the techniques proposed in this thesis. For these reasons, among others, stability limits are approximated by voltage stability limits since they reflect the "relative" stability of the network [21]. Furthermore, it is possible to use fast CPF techniques to evaluate these limits as well as gather sensitivity information required in the proposed security pricing methods.

2.2.2 Contingency Analysis

In contingency analysis, it is often desirable to consider how a system is affected by a limited number of contingencies at a time. Commonly, the N–1 contingency criterion is used which considers the effect of all reasonable *single* contingencies occurring. In the analysis, all bus voltage, thermal and voltage stability limits must be respected, and there can be no cascading outages [26]. Similarly, an N–2 analysis considers contingencies taken two at a time under the same conditions.

In this thesis, only transmission contingencies are considered, and contingency analysis using both N–1 and N–2 are considered in the examples discussed in Chapter 4. In contingency analysis, the CPF method is used to determine the appropriate loading margins and to ensure that security limits are not violated.

2.2.3 ATC Calculation

Mathematically, the ATC is defined as [15]:

$$ATC = TTC - TRM - ETC \tag{2.18}$$

where TRM is the transfer reliability margin; ETC represents the existing transmission commitments and includes the capacity benefit margin (CBM); the TTC is the total transfer capability of the system.

The TRM is designed to provide a reserve of capability to maintain reliability standards. It is defined as:

> The amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions [15].

The CBM is also a reserve margin for maintaining generation reliability standards, and is defined as:

> The amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements [15].

Mathematically, the TTC can be expressed as:

$$TTC = min.\ \{P_{max_{I_{lim}}}, P_{max_{V_{lim}}}, P_{max_{S_{lim}}}\} \tag{2.19}$$

where I_{lim}, V_{lim}, and S_{lim} represent the thermal, bus voltage and voltage stability limits respectively. Typically the N–1 contingency criterion is applied to the TTC calculation in (2.19) so that the maximum loadability of the system is defined under the single worst possible contingency. Throughout this thesis it is assumed that the N–1 contingency criterion is the basis for the ATC calculation.

Typical computations of the ATC for a sample system is explained graphically in Figures 2.5, 2.6, and 2.7. In this example, two PV curves are shown for a given system. The outer curve is the system under normal operating conditions, while the inner curve is the system PV curve under the worst single contingency. In

Figure 2.5, the bus voltage limits are active and define the TTC of the system under the worst contingency. In the example in Figure 2.6, the bus voltage limits are different and the thermal limits dominate the TTC determination. Finally, if both voltage and thermal limits are changed, as in the case depicted by Figure 2.7, then voltage stability limits dominate.

In [17], WECC provides MW margin guidelines for maintaining voltage stability in a system under various operating conditions. A margin of 5% is indicated for the PV method using N–1 contingency analysis, and it is applied in this thesis as the TRM term in (2.18).

The following steps are then used to calculate the ATC for a given system:

1. Determine the system conditions that comprise the ETC, and a value for the TRM.

2. Evaluate the direction of load change vector to be used in the CPF calculation. This vector is based on market auction results and/or load forecasts.

3. Define the set of all operating conditions under consideration. This includes all contingencies of interest as well as the normal operating case.

4. Identify the critical contingencies by the N–1 contingency criterion. Sensitivity analysis similar to the techniques proposed in [27] may be used here to identify the critical contingencies.

5. Evaluate the TTC in (2.19) by finding the maximum loadability of each critical contingency using CPF and the direction of load change from Step 2. A

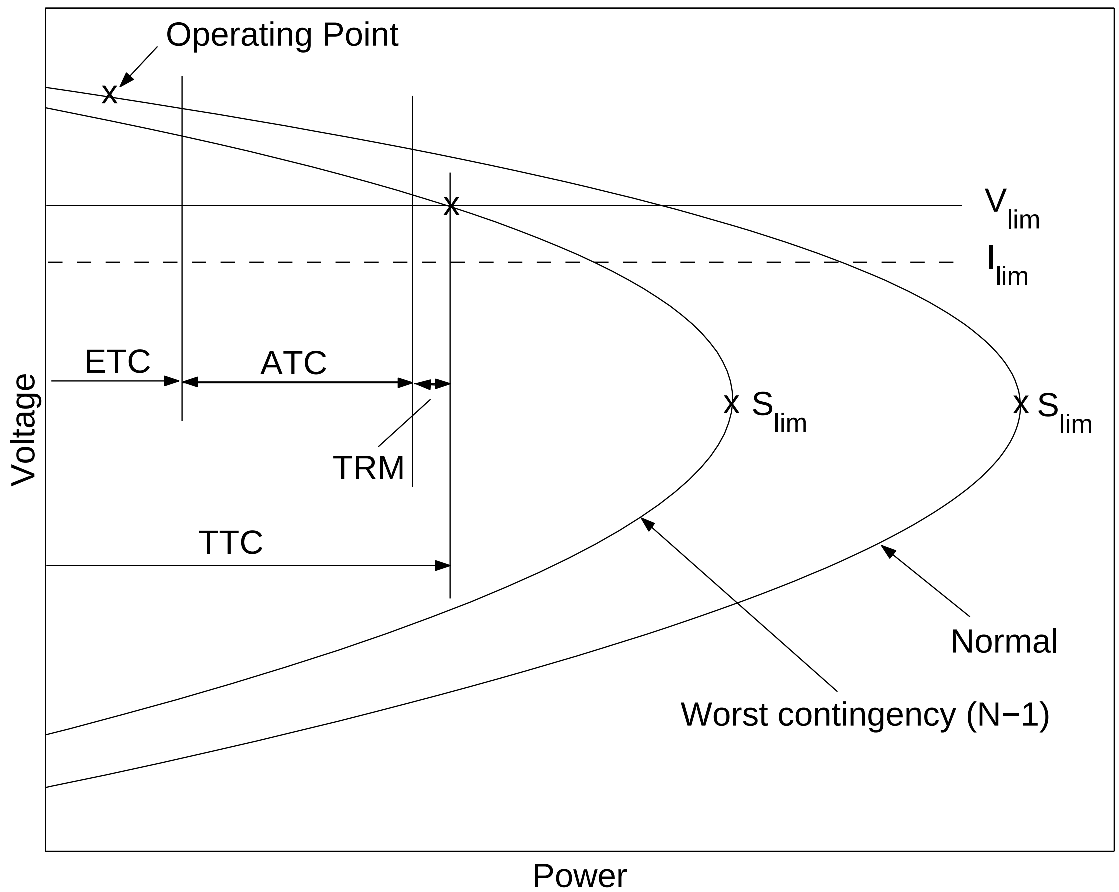

Figure 2.5: ATC evaluation where bus voltage limits dominate.

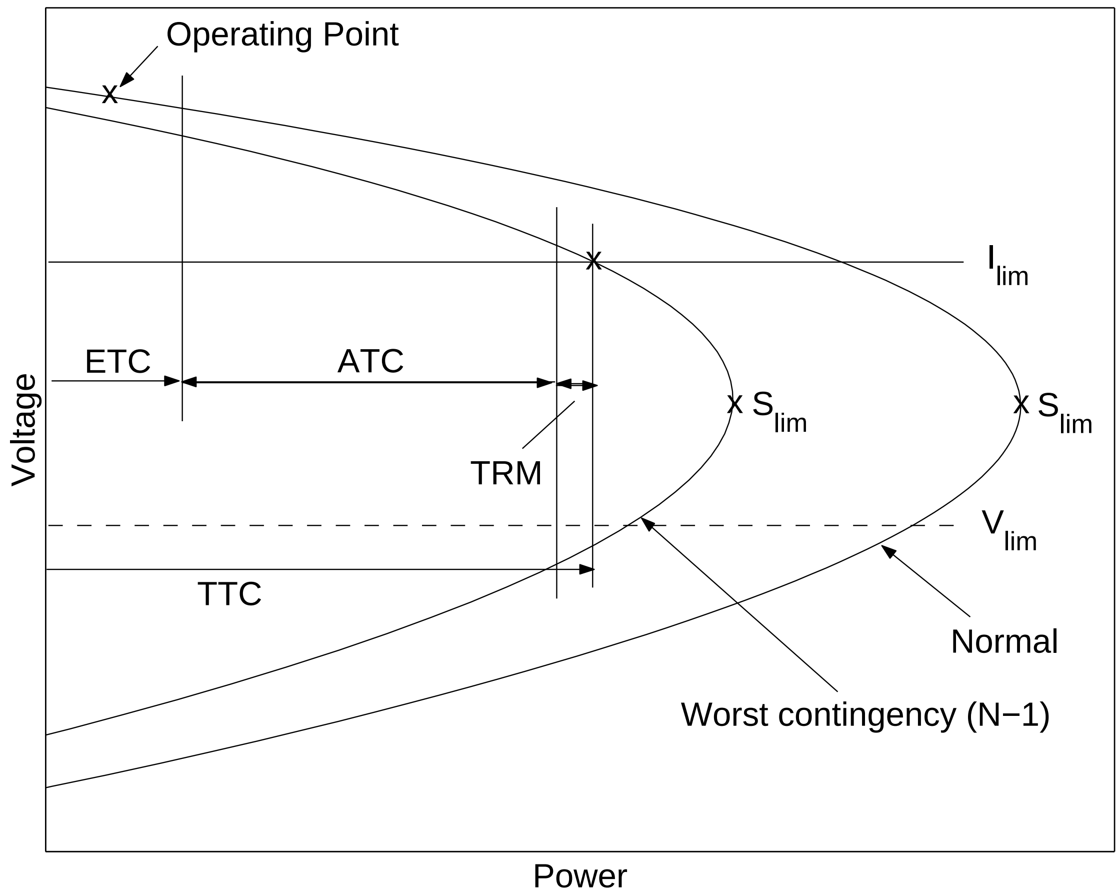

Figure 2.6: ATC evaluation where thermal limits dominate.

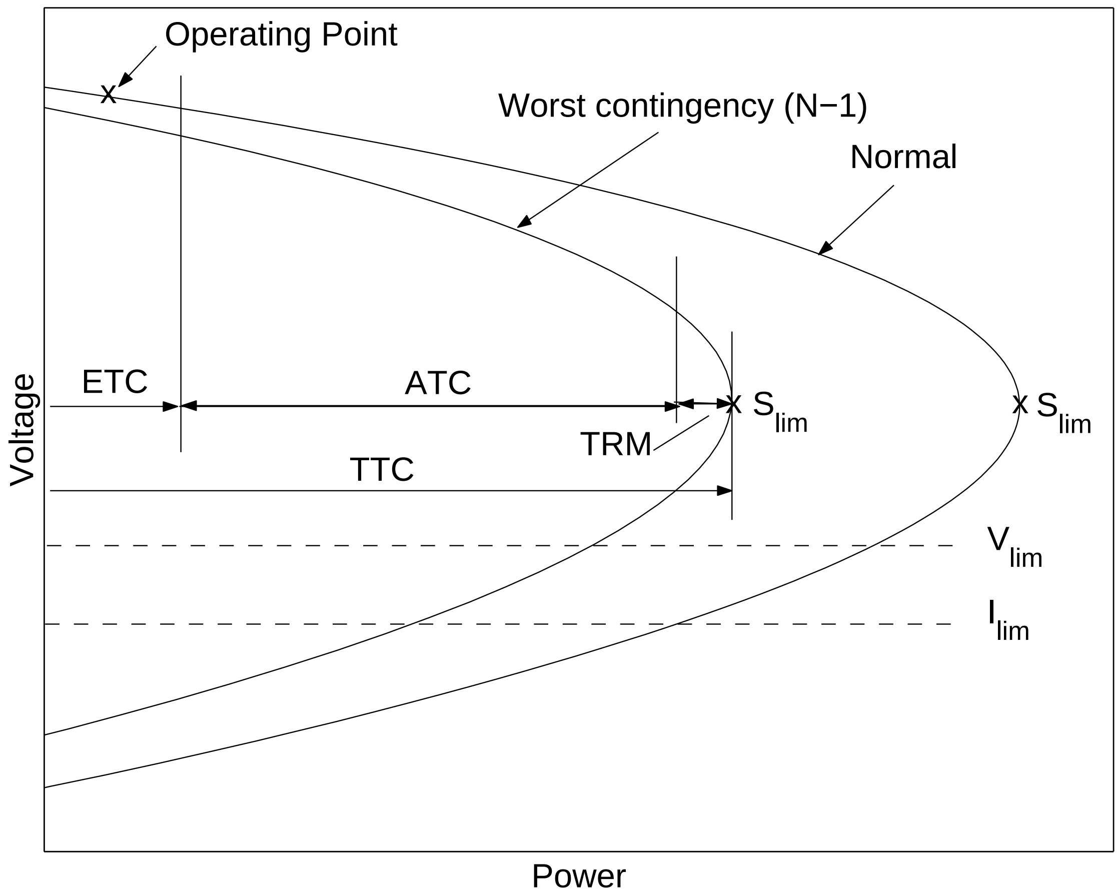

Figure 2.7: ATC evaluation where voltage stability limits dominate.

software program such as UWPFlow [28] can be used in this step.

6. Use the TTC from Step 5 as well as the ETC and TRM from Step 1 to evaluate (2.18).

The ATC has traditionally been used to assess security through power "corridors" (e.g. [14]). However, it can also be used as a system index since the formal definition does not limit its use to particular transmission corridors (e.g. [18]). In this thesis, the ATC is considered for the whole system; however, it is not used here as a security index to limit transactions, but rather as an index for sensitivity analysis.

2.3 Transaction Impact Calculation

The ATC is typically based on deterministic criteria, such as the N–1 contingency criterion [29]. Since it does not account for specific uncertainties in the system, it cannot reflect the risk of system security limit violations accurately. However, sensitivity information from the ATC can be effective at determining the impact of transactions on system performance, which is mainly the way it is used here [16], [19].

Each transaction will impact the system ATC, either positively or negatively. To ensure fairness, the cost of maintaining security must be distributed among the participants commensurate with their impact on the ATC. Sensitivity analysis predicts the effects of altered parameters by using linear approximations [22]. This analysis assesses the sensitivity of the ATC with respect to the transactions of each participant.

2.3.1 Sensitivity Analysis

To evaluate the ATC sensitivities, it is necessary to compute $dATC/dp$ for each participant in the system; by considering all participants, including those not directly bidding in the market, the influence of all parties on the ATC can be accounted for. These sensitivities are evaluated as follows: It is assumed that the system is at a stable equilibrium point (z_0, p_0, λ_0) of the dynamical system represented by the nonlinear field. In the sensitivity analysis used here, p represents the transactions in the system which, as mentioned earlier, includes all bids, contracts, and other existing commitments in the system. A small perturbation in the transaction parameters is represented as Δp, and it will move the system to another stable equilibrium point, $(z_0 + \Delta z, p_0 + \Delta p, \lambda_0 + \Delta\lambda)$, i.e.

$$F(z_0 + \Delta z, p_0 + \Delta p, \lambda_0 + \Delta\lambda) = 0 \tag{2.20}$$

The Taylor series expansion of (2.20) after neglecting higher order terms is reduced to:

$$D_z F|_0 \Delta z + D_p F|_0 \Delta p + D_\lambda F|_0 \Delta\lambda = 0 \tag{2.21}$$

where $D_z F|_0$, $D_p F|_0$ and $D_\lambda F|_0$ are the Jacobian matrices at the stable equilibrium point. The impact of the transactions on the ATC is then approximated as:

$$\frac{dATC}{dp} \approx \frac{\Delta L}{\Delta p} \tag{2.22}$$

where L is the loading margin for the system under the single worst contingency, and it is defined as follows:

$$L = \lambda_{max} \sum \Delta P_{L_i} \tag{2.23}$$

As previously discussed, the value for L can be associated with a SNB, a SLIB, or a given bus voltage or thermal limit depending on the system studied [21].

Saddle Node Bifurcations

As mentioned in Section 2.1.2, a SNB can be associated with a loss of voltage stability. In this case, the Jacobian matrix D_zF has a zero eigenvalue with an associated left eigenvector w (row vector) [22]. Then from (2.21):

$$wD_zF|_0\Delta z + wD_pF|_0\Delta p + wD_\lambda F|_0\Delta\lambda = 0 \tag{2.24}$$

Therefore, since $wD_zF|_0\Delta z = 0$ then (2.24) reduces to:

$$wD_\lambda F|_0\Delta\lambda + wD_pF|_0\Delta p = 0 \tag{2.25}$$

$$\Rightarrow \quad \frac{\Delta L}{\Delta p} = -\frac{wD_pF|_0}{wD_\lambda F|_0}\sum \Delta P_{L_i} \tag{2.26}$$

Limits

The value for L may also be affected by limits, i.e. voltage limits, thermal limits or SLIB. Unlike a SNB, $D_zF|_0$ is not singular at either a limit or SLIB, so (2.26) does not apply. A system that has reached a limit can be described by the following two equations:

$$F(z_0, p_0, \lambda_0) = 0 \tag{2.27}$$

$$\widetilde{F}(z_0, p_0, \lambda_0) = 0 \tag{2.28}$$

where (2.27) refers to the original system before the limit is reached, and (2.28) represents the modified system of equations *after* the limit is active. Given a small change in the transaction parameters, Δp, it follows that [16], [19]:

$$D_z F|_0 \Delta z + D_p F|_0 \Delta p + D_\lambda F|_0 \Delta\lambda = 0 \tag{2.29}$$

$$D_z \widetilde{F}|_0 \Delta z + D_p \widetilde{F}|_0 \Delta p + D_\lambda \widetilde{F}|_0 \Delta\lambda = 0 \tag{2.30}$$

It is then possible to eliminate Δz from the system of equations, leading to:

$$\frac{\Delta L}{\Delta p} = \frac{\mu^T (D_z \widetilde{F}|_0 D_z F^{-1}|_0 D_p F|_0 - D_p \widetilde{F}|_0)}{\mu^T \mu} \sum \Delta P_{L_i} \tag{2.31}$$

where

$$\mu = D_\lambda \widetilde{F}|_0 - D_z \widetilde{F}|_0 D_z F^{-1}|_0 D_\lambda F|_0 \tag{2.32}$$

The sensitivity formula in (2.31) can be applied to cases where either a bus voltage limit, thermal limit or SLIB is reached.

2.3.2 Implemented Solution

To evaluate the equations for the sensitivity analysis discussed, it is necessary to perform a detailed evaluation of the system equations under study. Although using these equations directly is the most desirable method for performing the sensitivity analysis, it is not used here given the limitations of the tools available. Hence, even though it is computationally more expensive, the implementation used in this thesis to calculate the sensitivities is based on perturbation analysis in conjunction with UWPFlow [28]. In Section 2.2.3, the most critical contingency is found to define the ATC under the N–1 contingency criterion. Once identified, each transaction is perturbed by Δp and the loading margin is evaluated again. By monitoring the change in the ATC under each perturbation of the transaction parameters, the $dATC/dp$ vector is approximated as:

$$\frac{dATC}{dp} \approx \frac{\Delta ATC}{\Delta p} \tag{2.33}$$

This process is summarized in Figure 2.8.

The results of the transaction impact analysis are positive for transactions that bolster the ATC, and negative for those that hinder it. In the following chapter, it is shown that the cost of maintaining system security is only assigned to transactions that negatively affect the ATC. These costs provide incentives to participants to operate the system in a way that minimizes the hindrance to the overall transfer capability.

2.4 Summary

In this chapter, the TI evaluation procedure is presented. Voltage stability and CPF concepts are reviewed since they are used to determine the loading margins for a system under various contingency scenarios. The impacts of individual transactions on the ATC index are considered, and quantified by using sensitivity analysis of the ATC to all transactions in the system.

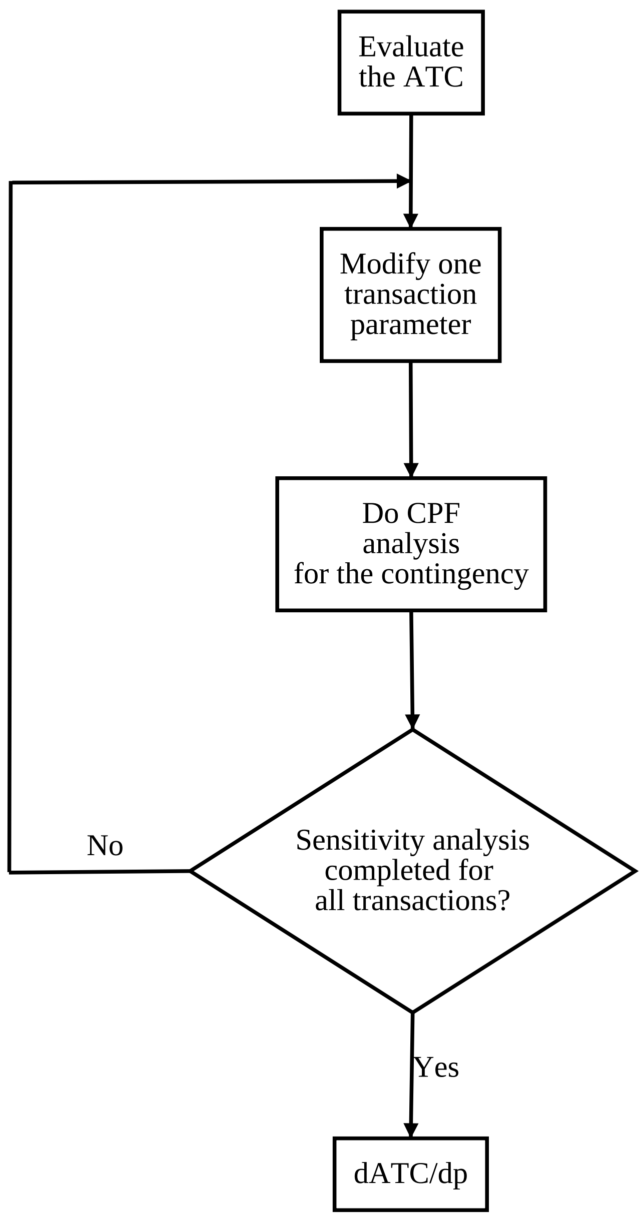

Figure 2.8: TI evaluation procedure using perturbation analysis.

Chapter 3

Security Cost Analysis

In this chapter, a comprehensive method for quantifying the security costs in a system is presented. Basic concepts in risk analysis and probability theory are reviewed. Furthermore, an equitable method for distributing security costs to participants commensurate with their impact on the ATC is developed.

3.1 Reliability Analysis

Reliability is a well-researched area that covers many aspects of system operation [30]. It is a broad concept that describes the ability of a system to meet the demands placed on it. However, it is often partitioned into two smaller concepts: security and adequacy.

In system planning, it is often necessary to assess whether there is enough generation to meet the forecasted load. This fundamental question related to the static operation of a power system is answered by an adequacy evaluation, which is defined as [26]:

> Adequacy is the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements

While the questions answered by an adequacy evaluation are numerous, it does not speak for the ability of a system to withstand sudden disturbances. Sources of such contingencies can include, among others: unexpected loss of major generation units, major weather conditions that take down transmission towers, serious faults *etc*. The impact of these conditions are covered in a security analysis, where security is defined as [26]:

> Security is the ability of the electric systems to withstand sudden disturbances such as short circuits or unanticipated loss of system elements.

In this thesis, security refers to the ability of a system to withstand transmission contingencies and still operate without violating any of the following security limits: thermal limits, bus voltage limits and voltage stability limits. The likelihood and severity of security problems form the basis for the risk-based security evaluation.

3.2 Risk-Based Security

Deterministic indices are commonly used in power system analysis to assess the severity or impact of certain events on system operations. Voltage stability margins are an example of such an index: if loading exceeds the voltage stability limit, voltage collapse could occur. However, there is no provision for evaluating the likelihood of voltage stability limits being exceeded. On the other hand, reliability theory incorporates probabilistic techniques into power system analysis.

Some of the results of reliability studies are indices to quantify the likelihood of events occurring that could affect the operation of the system [31]. Indices such as the loss of load probability (LOLP) incorporate the probability of a loss of load, but they do not quantify the severity of that loss on the system. Other indices such as the loss of energy expectation (LOEE) incorporate both probability and severity, but the severity term is limited to load interruption. The purpose of risk analysis is to measure the severity that a possible event may have, qualified by the probability of that event occurring. In this case, the severity term is generic, and can be tailored to suit any application.

Risk is defined as [32]:

$$Risk = Probability \times Severity \tag{3.1}$$

In the risk-based security analysis of a power system presented in this thesis, the probability of transmission contingencies occurring, and their impact on the system is at the heart of the security assessment. The influence of these outages on the violation of thermal limits, bus voltage limits and voltage stability limits are considered. The goal is to understand the aggregate effect of transmission contingencies on *all* of the aforementioned security limits to develop a comprehensive risk assessment of the security of the system. The probability of transmission contingencies occurring is assumed to be Poisson distributed, and is discussed next.

3.2.1 Poisson Process

The Poisson process $\{N(t),\ t \geq 0\}$ is a counting process that has many applications. As a counting process, it represents the number of events that occur up to a time, t. To be Poisson, a process must possess the following properties [33]:

1. $N(0) = 0$
2. The process is memoryless, or has "independent increments."
3. The number of events that occur in a time interval t is Poisson distributed with mean γt.

The first condition implies that counting begins at time zero. The second condition means that the number of events that occur in one interval are independent of events in all other intervals; for example, the number of events that occurred in the past five years will not affect the number that occur over the next year. The final condition defines the Poisson distribution which is used in this thesis, and it can be stated mathematically for all time intervals u, $t \geq 0$ as:

$$Pr\{N(t+u) - N(t) = i\} = e^{-\gamma t}\frac{(\gamma t)^i}{i!} \tag{3.2}$$

where γ is referred to as the "rate" of the process, and for the purposes of this thesis it is the average number of transmission contingencies per unit time. Note that the Poisson distribution in (3.2) is a probability mass function [34], as the probabilities of all possible events add up to unity:

$$e^{-\gamma t} \sum_{i=0}^{\infty} \frac{(\gamma t)^i}{i!} = e^{-\gamma t} e^{\gamma t} = 1 \tag{3.3}$$

The Poisson distribution is well-suited for modeling the number of occurrences of random phenomenon in a specified interval of time [34]. In this thesis, it is used to predict the number of transmission contingencies that will occur in a bidding period in an electricity market. It is well-suited for contingency analysis because it requires only the average number of occurrences per unit time γ, and the time interval t under consideration [12].

3.2.2 Probability of Contingencies

In any realistic power system, there are numerous sources of uncertainty. For the purposes of this thesis, the uncertainties under consideration are credible transmission contingencies that cause a change in operating state for the whole system. As discussed earlier, reliability analysis is a well-researched area that handles system contingencies probabilistically. For example, individual components are assigned failure rates based on historical data that is usually documented by utilities [35]. In this thesis, failure rate data from reliability studies are used along with the Poisson distribution to evaluate the probability of transmission contingencies.

As a system operator, the loading over the next time period is assumed known based on all transactions submitted by the participants. During operation, there will be some deviation in the actual values from those submitted to the operator. However, it is assumed that the variance of these submitted values will be small so that an analysis of uncertainty in the load and supply is not implemented.

As discussed in Section 2.2.2, systems are often studied using N–1 or N–2 contingency analysis. To be consistent with this definition, the probability function used must satisfy two conditions. First, the probability that a contingency set occurs at *least* once in a given interval of time. Secondly, that no other sets of contingencies occur during the same interval:

$$\begin{aligned} Pr(E_k) &= Pr(E_k \text{ occurs at least once}) \times Pr(\text{no other contingencies}) \\ &= Pr(E_k > 0) * \prod_{m \neq k} Pr(E_m = 0) \\ &= (1 - e^{-\gamma_k t}) * \prod_{m \neq k} e^{-\gamma_m t} \end{aligned} \tag{3.4}$$

where E_k represents the contingency set under consideration, and t is the time interval of interest. Throughout this thesis, t is the next bidding period in a power market, which is usually set to one hour as suggested in [12]. Additionally, γ is the outage rate of the contingency based on historical data. It is an average value that aggregates outages over all loading levels experienced by the system.

3.3 Security Cost Calculation

To evaluate the cost of maintaining voltage security, it is necessary to incorporate the uncertainty of contingencies occurring in the system as presented in Section 3.2.2. In this thesis, risk is extended to a security cost, where the severity term in (3.1) is a dollar-based cost assigned to a system security violation (S.V.).

In a security cost evaluation, the outcome under consideration is whether a voltage stability, bus voltage or thermal limit violation would occur. It requires evaluating the probability of a contingency occurring and the associated security violation cost should the contingency occur. This process is repeated for each contingency under consideration. It is then possible to evaluate the security cost at each loading level of interest to establish a security cost profile for the system. The mathematical expression for security cost is then [11], [19]:

$$SC(X_0) = \sum_k Pr(E_k) * C_{S.V.}(E_k, X_0) \tag{3.5}$$

where X_0 is the system loading under consideration and $Pr(E_k)$ is the probability of contingency set E_k occurring. Therefore, $C_{S.V.}(E_k, X_0)$ is the cost function for a security violation under a given contingency E_k, evaluated at the current loading X_0. Recall that in (3.4), $Pr(E_k)$ is the probability of the k^{th} contingency set occurring and the probability of all other contingencies *not* occurring during the time interval t. Therefore, it is possible to express (3.5) as a simple summation [33].

The cost function, $C_{S.V.}(E_k, X_0)$, found in (3.5) provides flexibility to the application of this method. Individual jurisdictions can make this function as simple or as sophisticated as necessary to satisfy their operational requirements. In this thesis, a discrete cost function based on the system limits is used and illustrated in Figure 3.1 along with corresponding PV curves. In this example, only one contingency is considered but all security limits are included. As shown, there is no associated cost if this contingency occurs at any loading condition less than 625MW since it is assumed that the system would still be able to operate normally. However, at loading conditions greater than 625MW, voltage limits would be violated, so there is a "jump" in the cost function. Similarly at 709MW there is a thermal limit for the system under the given contingency, so there is another increase in the cost function. Lastly, there is a voltage stability limit at 720MW which could lead to voltage collapse if exceeded. When thermal or voltage limits are violated, it is assumed that the event is not "catastrophic" for the system, *i.e.*, there is time to take remedial action to relieve the system. However, when a voltage stability limit is violated, it is assumed that a catastrophic voltage collapse ensues, which is clearly more expensive. Therefore, the cost function increases significantly under this security violation.

The result of (3.5) is a bulk security cost for the system, which is a reflection of the risk that the system stakeholders assume when operating the system at a given point, X_0. This value can then be used to compare the risk of operating the system at the level of the "potential" transactions, to the level indicated by deterministic criteria such as the ATC. Furthermore, it can be distributed among the participants based on the impact of the transactions on the ATC, as discussed next.

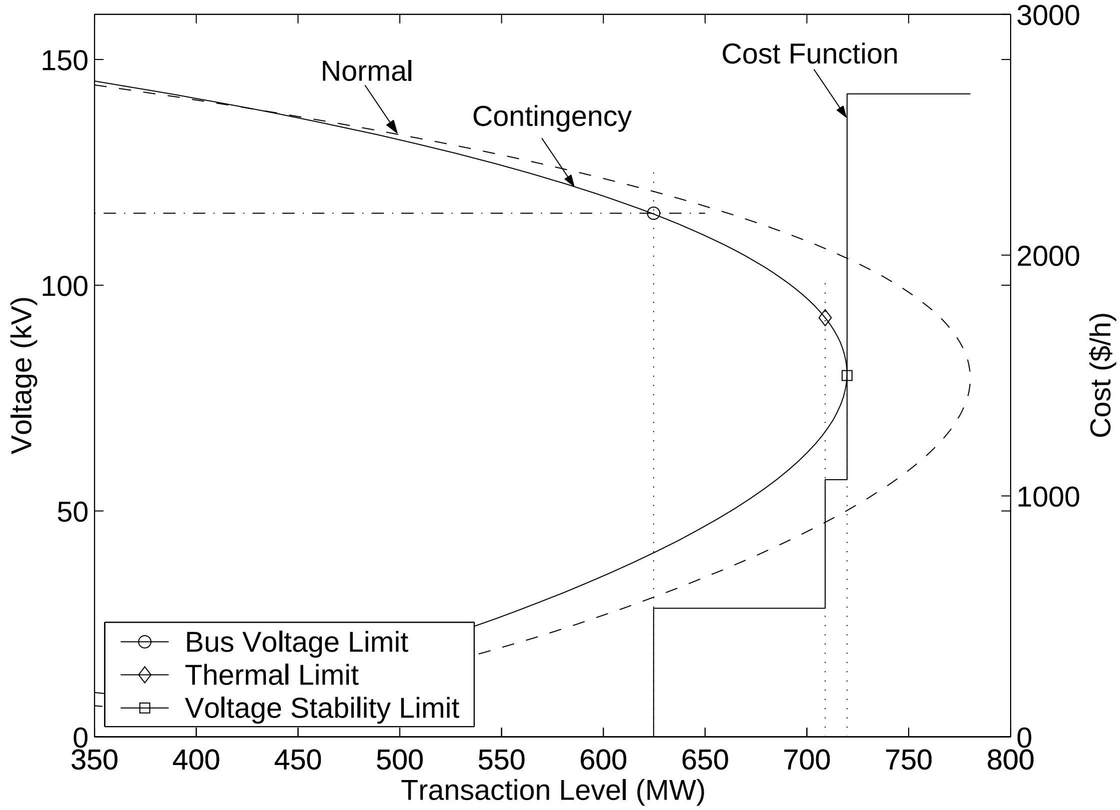

Figure 3.1: Sample cost function.

3.4 Transaction Analysis

After evaluating the bulk security cost of operating a system at a given point, it is important for operators to be able to distribute it equitably to all participants based on the impact of their transactions on the ATC. The method with which this cost is distributed is discussed below.

3.4.1 Transaction Contribution Factor (TCF)

Using the sensitivity information gathered in Chapter 2, it is possible to determine the relative effect of each transaction on the system security, as evaluated using the ATC index. A transaction contribution factor (TCF) to security problems is then defined as [19]:

$$TCF_i = \frac{(dATC/dp_i) * p_i}{\sum_{j=1}^{N}(dATC/dp_j) * p_j} \tag{3.6}$$

where p_i is the power level of transaction i in a system with N participants. The security cost for each transaction as defined here is dependent on the extent to which each transaction impacts the ATC relative to all participants in the system. Note that participants that are not in the market are also included here. Some participants only have transactions that are included in the existing commitments which form the base operating condition. However, the transactions of those participants not directly bidding in the market also affect the ATC, and hence are included in the analysis.

3.4.2 Transaction Security Cost (TSC)

The contribution of each transaction is then translated into a transaction security cost (TSC) which is the product of each TCF and the bulk security cost at a given loading level X_0:

$$TSC_i(X_0) = SC(X_0) * TCF_i \tag{3.7}$$

To provide proper incentives to participants, security costs should only be levied to those who hinder the ATC, while those who bolster it should not be penalized. Therefore, transactions that have a positive impact on the ATC are assigned a TCF of zero so that they are not assigned a security cost. It is expected that the money being paid to the operator may be used to improve the system performance, but these particular issues are beyond the scope of this thesis.

3.5 Discussion

The security cost method presented in this chapter incorporates risk analysis into a uniform pricing market structure. The TSC represents an adjustment to the price that encapsulates the risk of security limit violations. There are OPF-based techniques available that produce similar revenue as per the costs of operating the system [6]. The advantage of the technique proposed here versus OPF is that it is transparent, simpler to implement, and it does not present "convergence" difficulties, with the obvious caveat that it is not optimal.

Recall that the ATC is typically used as a limit on the amount of extra capacity available in the system (typically in given transmission corridors), and is based on the N–1 criterion. However, a system security violation can occur under any number of contingencies, not just N–1. Therefore, the ATC is used here to analyze the effect of transactions on the system security and not to limit transaction levels.

3.6 Summary

In this chapter, the framework for security cost analysis using probabilistic techniques is developed. The Poisson distribution is used to evaluate the probability of transmission line contingencies, which is based on historical reliability data for transmission line failure rates collected by utilities. This security cost is based on the probability of contingencies occurring and the cost of the associated security limit violations. The TI technique developed in Chapter 2 is then used to develop the TCF which is implemented in a TSC framework to equitably distribute the bulk security cost among the participants.

Chapter 4

Example Systems

In this chapter, the security cost analysis techniques are applied to two systems. The first system is a six-bus test system, which is analyzed under both N–1 and N–2 contingencies. The second system is a 129-bus model of the Italian HV system which is evaluated using the N–1 contingency criterion. In both cases the results are compared with deterministic criteria.

4.1 Cost Function

For both the six-bus system and Italian system examples, the following cost function is used in the evaluation of (3.5): It is assumed that a voltage stability limit violation will result in voltage collapse of the system; in such cases, a cost of $10000/MWh is used [19]. However, it is expected that bus voltage limit or thermal limit violations would not have as great an impact, and are assigned a cost of $2000/MWh.

Therefore, for the k^{th} contingency E_k, the cost function can be stated formally as:

$$C_{S.V.}(E_k, X_0) = \begin{cases} \$2000/MWh & \text{if } X_0 > V_{lim_k} \text{ or } I_{lim_k} \quad (4.1a) \\ \$4000/MWh & \text{if } X_0 > V_{lim_k} \text{ and } I_{lim_k} \quad (4.1b) \\ \$10000/MWh & \text{if } X_0 > S_{lim_k} \quad (4.1c) \end{cases}$$

It is assumed that a security limit violation will affect the entire system, so these costs are proportional to the total system load. For the sake of simplicity, almost all contingencies are assumed to have the same cost functions in the examples below. An exception to this assumption is described in the Italian system example where isolated nodes can occur, and it is discussed further in Section 4.3.2.

4.2 Six-bus Test System

The six-bus system used is a modified version of the system found in [36], and is shown in Figure 4.1. The full system data for this system is reproduced in Appendix A. Thermal limits on each line are set to twice the current level at base operating conditions, and upper and lower bus voltage limits are set to 1.21/0.84pu. Generally, bus voltage limits of 1.1/0.9pu are used; however, in this system the limits are looser to emphasize the cost of a bus voltage limit violation. Recall that the cost function $C_{S.V.}$ in (3.5) reflects the severity of a security limit violation should it occur. By "loosening" the bus voltage limits, the possible damage to the system increases when they are exceeded. Note that both the cost function and the bus voltage limits can be set to any desired value, or even multiple levels if so desired, permitting flexibility in their application.

Table 4.1: Six-bus System Bids

Participants	Quantity (MW)	Bid Price ($/MWh)
GENCO 1	20	9.7
GENCO 2	25	8.8
GENCO 3	20	7
ESCO 1	25	12
ESCO 2	10	10.5
ESCO 3	20	9.5

In this system there are six participants, three are ESCOs and three are GENCOs. Their bidding information is presented in Table 4.1. The total power level at base loading conditions for the system is 280MW. With the addition of 45MW cleared in the market, the total power level at the level of the potential transactions is 325MW.

In this example, a high-low bid matching procedure is used to establish the market clearing price (MCP) at $9.5/MWh, and it is illustrated in Figure 4.2. As shown in this figure, GENCO 1 is not cleared in the market because its bid price is too high. Similarly, ESCO 3 only has 10MW cleared out of its original bid of 20MW. These auction results are tabulated in Table 4.2 which shows the detailed results of the auction where ΔP is the cleared bid, and ΔQ is the corresponding reactive power demand assuming constant power factor; these form the direction of load change vector in the CPF evaluation. Base power levels are also shown for comparison.

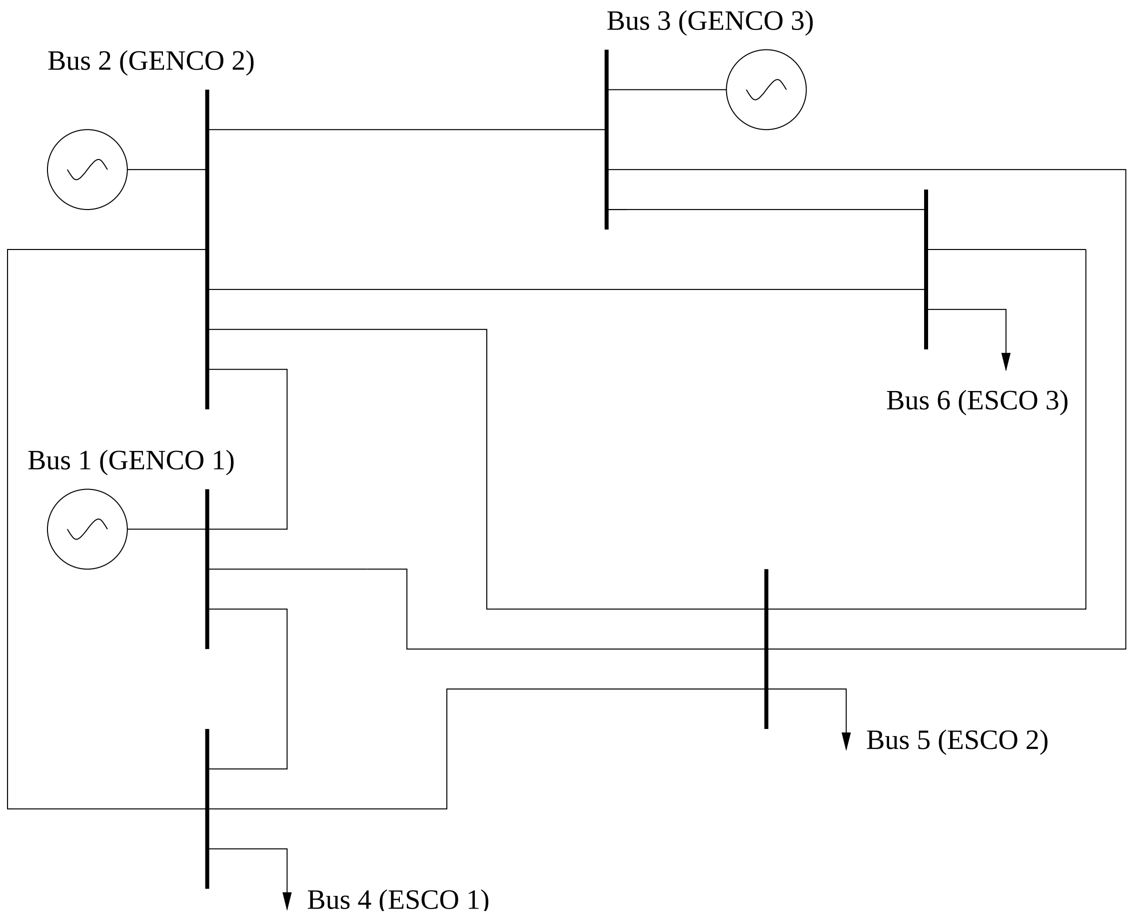

Figure 4.1: Six-bus test system.

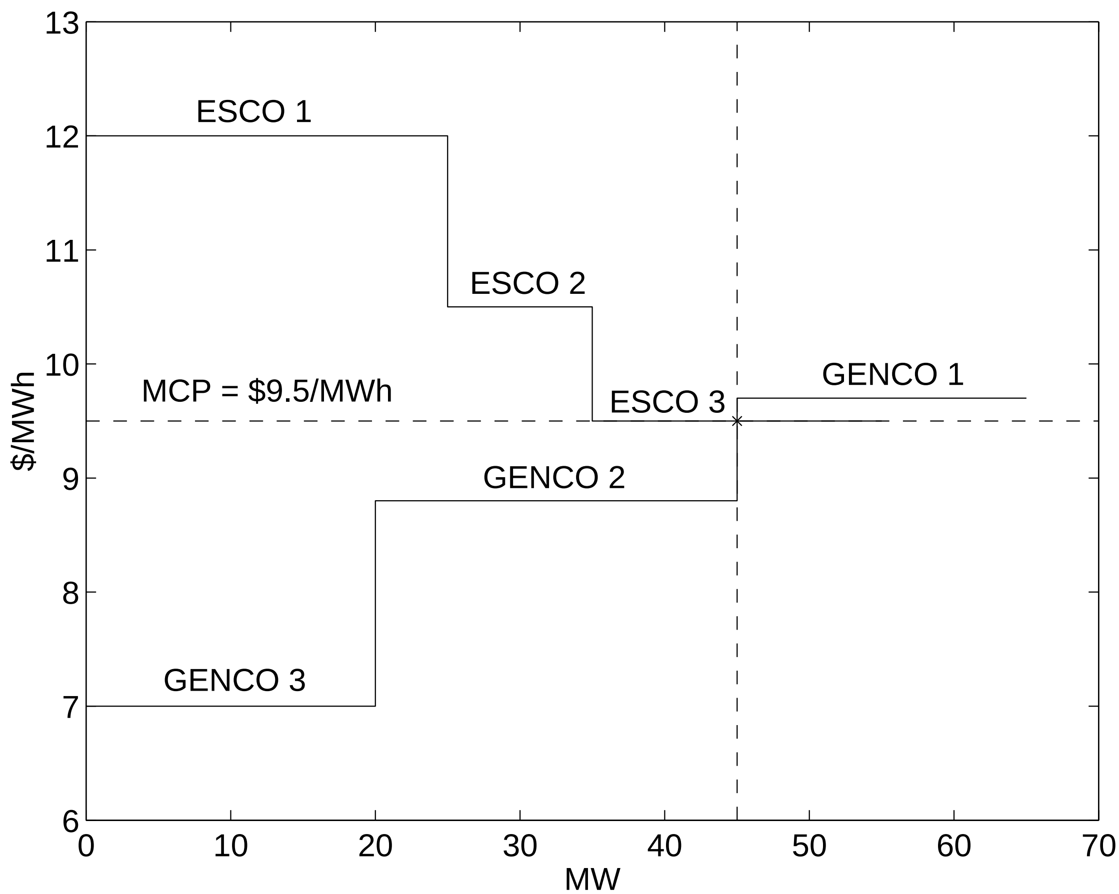

Figure 4.2: Six-bus test system auction procedure.

Table 4.2: Six-bus System Auction Results and Base Power Levels

Bus	P_G (MW)		P_L (MW)		Q_L (Mvar)	
	P_{G_0}	ΔP_G	P_{L_0}	ΔP_L	Q_{L_0}	ΔQ_L
1	89.87	0	0	0	0	0
2	140	25	0	0	0	0
3	60	20	0	0	0	0
4	0	0	90	25	60	16.7
5	0	0	100	10	70	7
6	0	0	90	10	60	6.67

4.2.1 ATC Evaluation

In evaluating the ATC, the N–1 contingency criterion is used to find the contingency with the largest impact on the TTC. The six-bus system has eleven branches and thus eleven possible contingencies using N–1; therefore, the TTC is evaluated for each of these eleven cases.

The results of the TTC evaluation using the CPF technique for each of the contingencies are listed in Table 4.3 along with the TRM values and transmission line failure rates. Failure rates for each transmission line in the system are listed in the second column of Table 4.3, and they are assumed to be proportional to impedance. As mentioned earlier, in [17], a 5% MW margin is suggested for the WECC operating region, and this margin is used in the ATC evaluation here. The TRM term is then 5% of the associated TTC value. The ETC for the six-bus system is assumed to be the base operating condition, which in this case is 280MW. As

Table 4.3: Six-bus System ATC Evaluation

Line Contingency	γ (fails./yr.)	TTC (MW)	TRM (MW)
GENCO 2 – ESCO 1	**0.20**	**318.26**	**15.91**
GENCO 3 – ESCO 3	0.20	339.99	17.0
GENCO 1 – ESCO 1	0.39	384.81	19.24
GENCO 1 – ESCO 2	0.59	455.28	22.76
GENCO 3 – ESCO 2	0.51	468.07	23.4
GENCO 2 – ESCO 2	0.59	498.05	24.9
GENCO 2 – ESCO 3	0.39	510.02	25.5
ESCO 2 – ESCO 3	0.59	515.7	25.79
ESCO 1 – ESCO 2	0.78	516.88	25.84
GENCO 2 – GENCO 3	0.49	517.61	25.88
GENCO 1 – GENCO 2	0.39	517.92	25.9

shown, a contingency on the line connecting GENCO 2 to ESCO 1 has the greatest impact on the TTC of the system, and so the ATC for the six-bus system is:

$$\begin{aligned} ATC &= TTC - TRM - ETC \\ &= 318.26MW - 15.91MW - 280MW \\ &= 22.35MW \end{aligned}$$

4.2.2 Security Cost Results

In the six-bus system, the transaction security costs are evaluated under both N–1 and N–2 contingencies. In Figure 4.3 a plot of the security cost profile of the six-bus system is shown using the N–1 contingency criterion. Recall that each step corresponds to a security limit for a contingent PV curve and an increase in the system security cost. The power level associated with the potential transactions that are cleared in the market is indicated along with the ATC. At the loading level associated with the ATC there is theoretically no risk of a security violation because there is no single contingency with a security limit occurring below the ATC. However, this condition does not hold true if more than one contingency is considered at a time as explained below.

The results for the N–2 analysis are shown in Figure 4.4, and indicate that the additional costs incurred by considering contingencies using N–2 analysis are small due to the low probability of two contingencies occurring during the same time interval. Using N–2, there are two sets of contingencies where the system solution does not converge. Therefore, there is a risk of a security limit violation and thus a small security cost of \$0.00645/h associated with the base loading of the system at 280MW, without any additional loading from the market. Similarly, at the loading level associated with the ATC (302.35MW) there is a small security cost of \$0.0102/h. This cost implies that there is a risk of a security violation associated with running the system at the ATC, even though that risk is negligibly small in this particular example.

The additional security costs incurred at the power level of the potential trans-

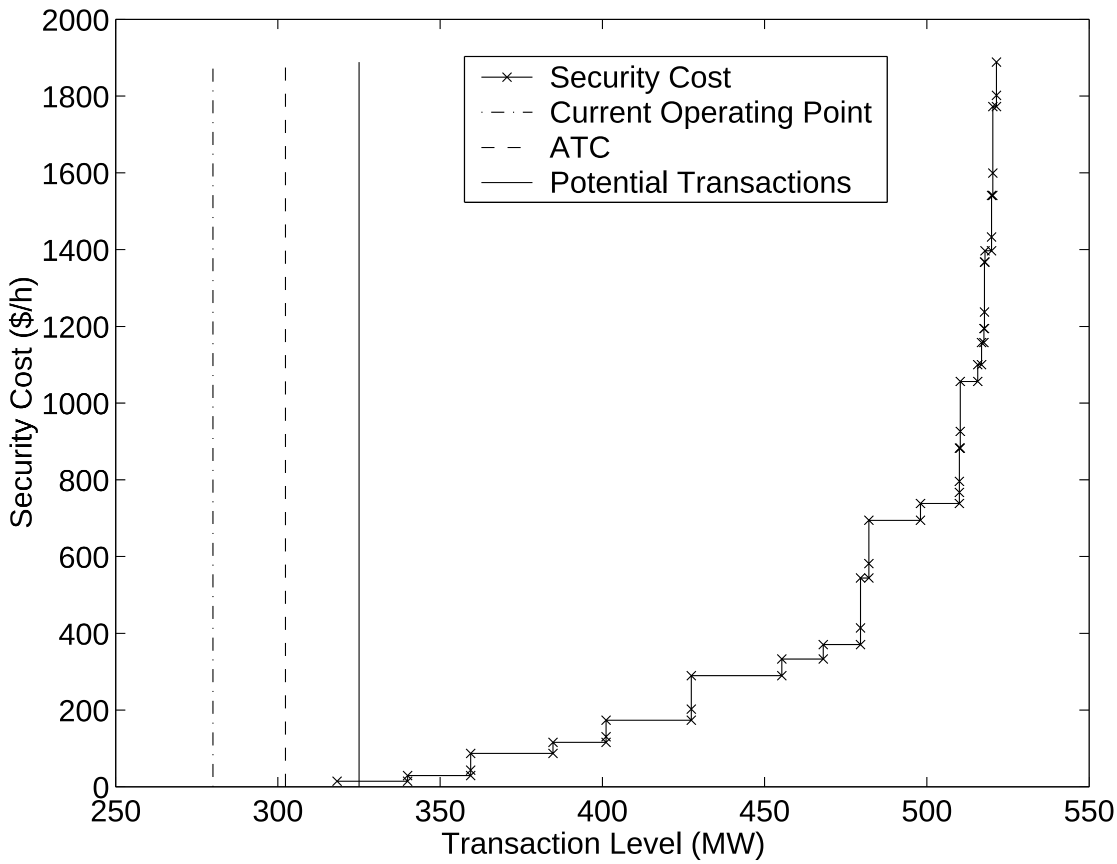

Figure 4.3: Security cost profile for the six-bus system under N–1.

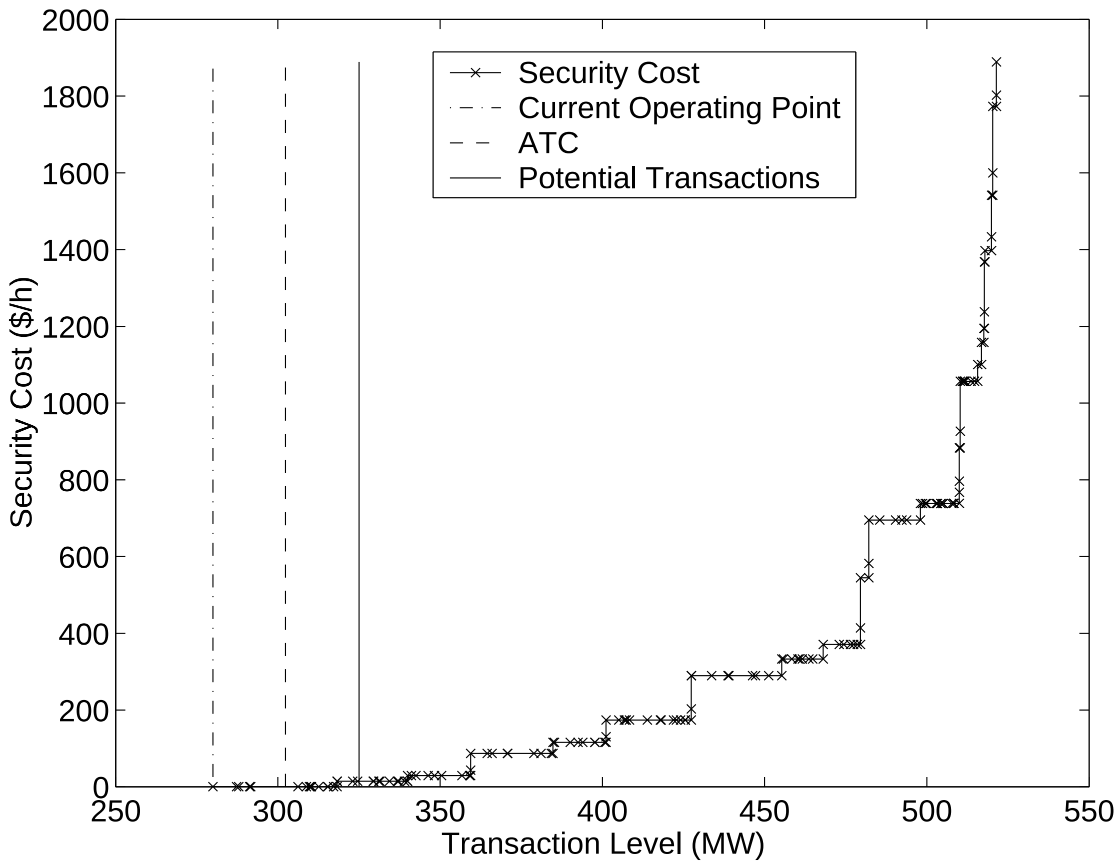

Figure 4.4: Security cost profile for the six-bus system under N–2.

actions are relatively small, but these transactions would not be permitted in most jurisdictions due to the ATC violation. There is always a risk of a security limit violation when operating a real system, even at the ATC and below. However, when the security costs involved are known to be small, it could be argued, that based on the results shown here, it is reasonable to allow additional transactions to occur in this system, even if the ATC is exceeded.

4.2.3 Transaction Results

The results of the TI analysis for the generators are:

$$\left[\frac{dATC}{dp_{G_1}} \quad \frac{dATC}{dp_{G_2}} \quad \frac{dATC}{dp_{G_3}}\right] = [0.95 \quad -0.03 \quad 0.03] \tag{4.2}$$

and for the loads:

$$\left[\frac{dATC}{dp_{L_1}} \quad \frac{dATC}{dp_{L_2}} \quad \frac{dATC}{dp_{L_3}}\right] = [-1.55 \quad -0.49 \quad -0.09] \tag{4.3}$$

The impacts show that GENCO 1 and GENCO 3 have a positive impact on the system ATC, while the remaining participants have a negative impact.

The TSC results for each bus are shown in Table 4.4 along with the TCF values and the security costs for the system over the next one hour period. The results show that GENCO 1 and GENCO 3 are not assigned security costs because they have a positive impact on the system ATC. However, GENCO 2 and all three ESCOs have a negative impact on the system ATC and they are assigned security costs. In the second column of Table 4.4, the total value of the transactions at a given bus are shown without a security cost added. For the purposes of comparison,

Table 4.4: Six-bus Transaction Security Costs for a 1 Hour Period

Bus	Transaction Value at MCP ($/h)	TCF	TSC ($/h) N–1	TSC ($/h) N–2	TSC (%) N–2
1	853.77	0.0	0.0	0.0	0.0
2	1567.50	0.020	0.291	0.291	0.02
3	760.00	0.0	0.0	0.0	0.0
4	1092.50	0.724	10.481	10.499	0.96
5	1045.00	0.219	3.169	3.1746	0.30
6	950.00	0.037	0.529	0.530	0.06
Totals:	6268.77		14.47	14.49	0.23

the transactions are priced at the MCP even though there are potentially other contracts with prices different from the MCP. These values provide a good measure for comparing the scale of the security cost relative to the total transaction value. In this system, the TSC values are reasonable when compared with the overall transaction cost, amounting to no more than 1% of the total cost for any participant.

4.3 129-bus Italian System Model

The security cost analysis is also applied to the 129-bus, 400kV Italian system model. This system is shown in Figures 4.5 and 4.6.

Bidding data for the 32 generators and 82 consumers in the system vary between $30-40/MWh, and they are based on average bid prices in other European countries

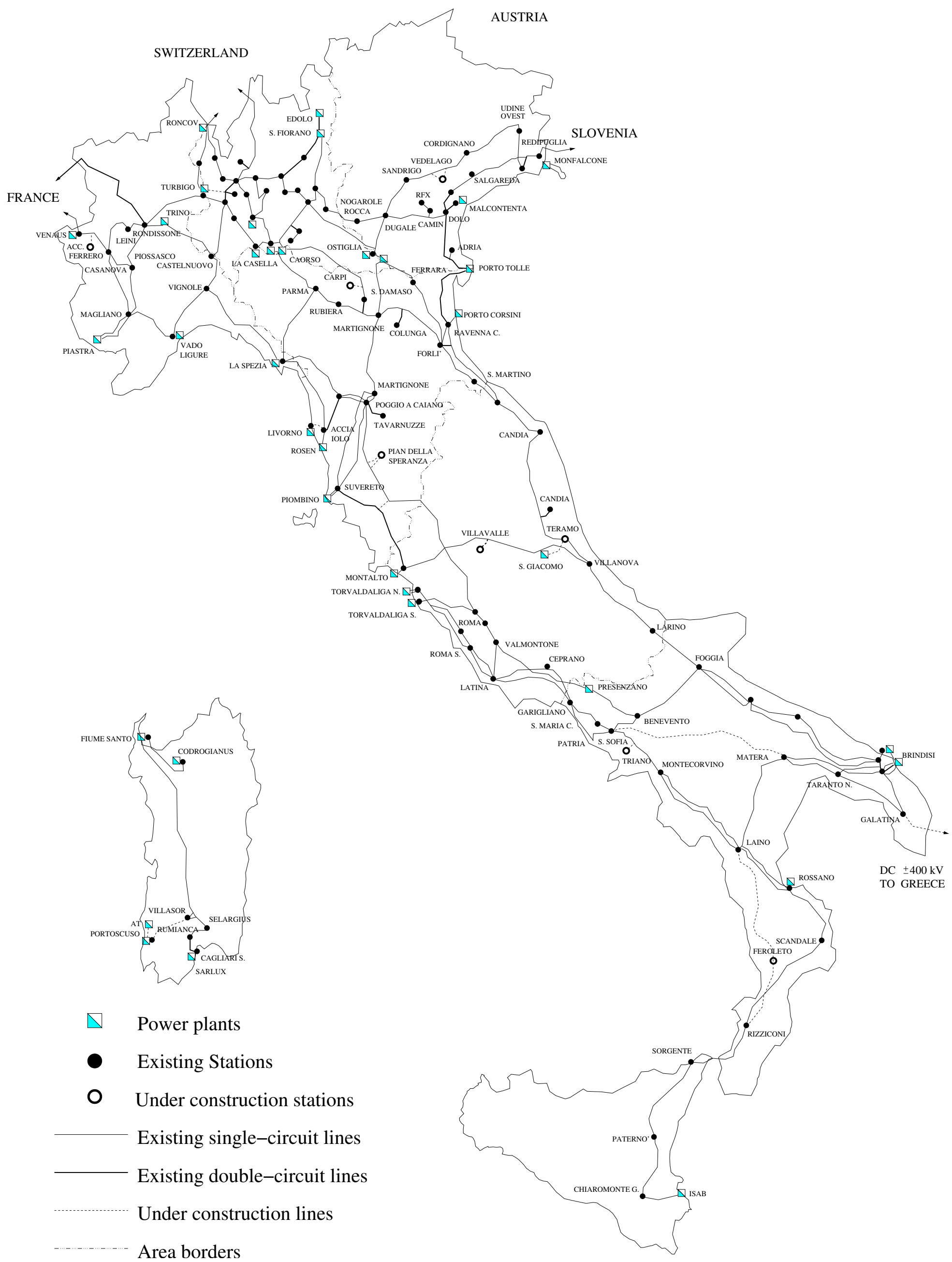

Figure 4.5: Map of the Italian transmission system.

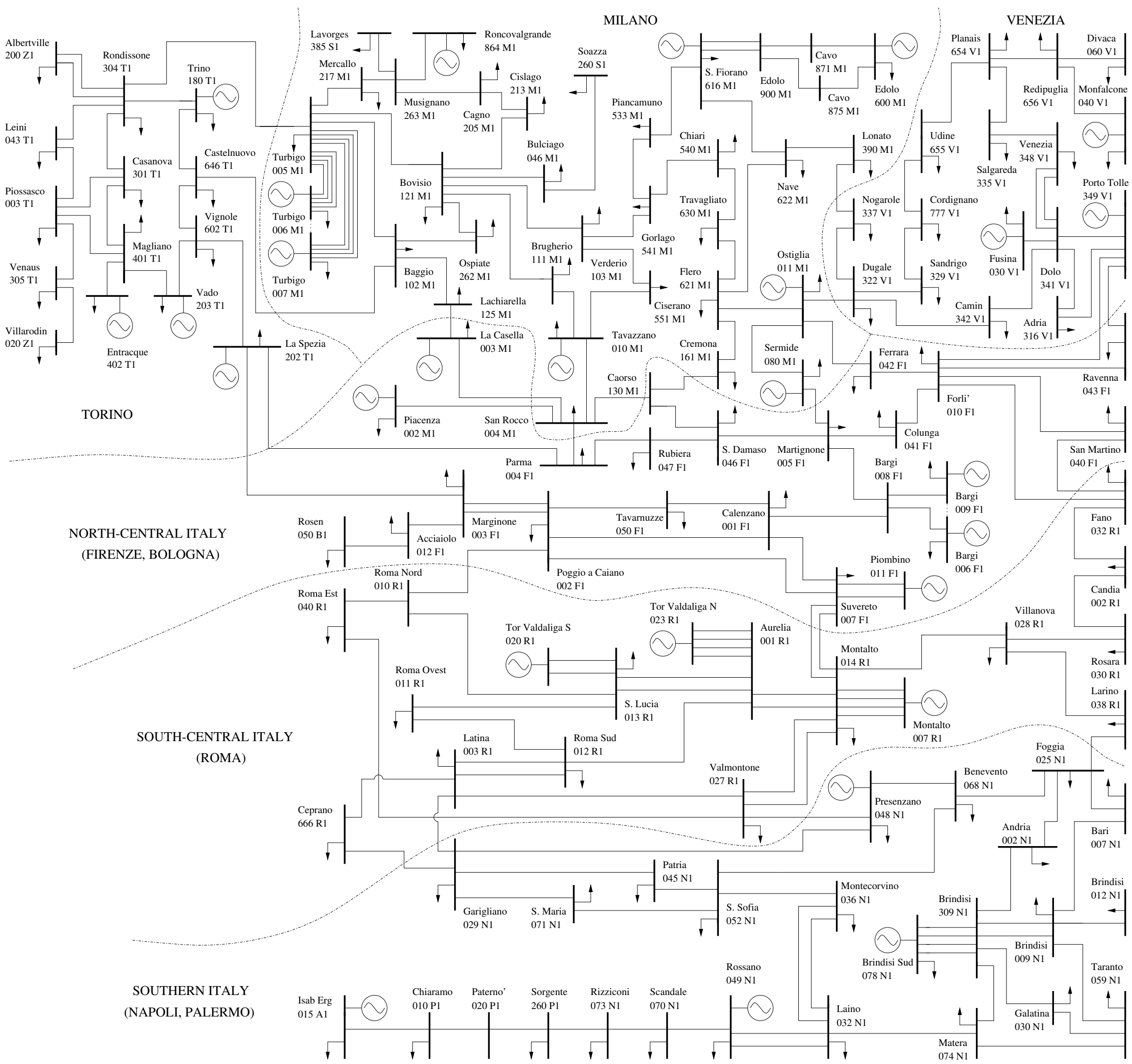

Figure 4.6: 129-bus Italian system model one-line diagram.

with active markets [6]. All system data is provided by CESI, the Italian electrical research center. Upper and lower bus voltage limits are set to 1.18/0.9pu. Again, these limits reflect levels at which damage to the system is expected as specified by the cost function (4.1), but they can be modified if necessary as discussed in detail in Section 4.2. Reliability data for the Italian system model was not available, so it is assumed that the failure rates vary linearly with line length. The average impedance is known to be 0.37 Ω/km, and the assumed failure rates are listed in Appendix B. Only realistic contingencies are considered in the analysis.

4.3.1 ATC Evaluation

As in the six-bus system, to evaluate the ATC for the Italian system model, it is necessary to perform an N–1 contingency evaluation on the system. For this system, there are 167 branches, so the system TTC is considered given a contingency on each of these branches. An exhaustive and computationally expensive approach to contingency evaluation is needed because (3.5) is evaluated over all contingencies, as discussed in later sections. This approach is manageable for the systems studied in this thesis, but it may be possible to find ways to reduce the computational burden. This would be the subject of future research.

As in the six-bus system, a 5% TRM value is also applied to the Italian system. A complete listing of the TTC and TRM values for each possible contingency are given in Appendix B. The single worst contingency occurs on the branch between buses 36 and 50 (Baggio and Turbigo). The ATC calculation for this contingency is:

$$\begin{aligned} ATC &= TTC - TRM - ETC \\ &= 20422MW - 1021MW - 17016MW \\ &= 2385MW \end{aligned}$$

There are some contingencies that cause buses to be isolated from the rest of the system. Under these conditions, it is not possible to perform a CPF evaluation for the system. These contingencies are not included in the ATC evaluation because it is assumed that these contingencies would not cause a system-wide security violation; rather, the effects would be localized to individual buses. However, it is shown below that security costs for these contingencies can be included in the security cost analysis.

4.3.2 Security Cost Results

The MCP for the system is \$34.40 with 3822.49MW of potential transactions being cleared above the current operating point of 17016MW. The security cost profile for the Italian system is shown in Figure 4.7. Notice that at the current operating point or base loading condition, which is an actual system operating condition, there is a security cost of \$876.3/h. This cost is due to contingencies that isolate certain nodes on the system, thus leaving some loads unserved. These isolating contingencies were probably not considered "significant" for the system as a whole by the operators. For these contingencies, the isolated loads are identified and the unserved energy is calculated for each case. Since these contingencies do not cause a security violation that affects the whole system, the cost used in (3.5) for these contingencies is \$10000/MWh, but it is only proportional to the *unserved* energy to the isolated loads.

The security cost for the loading level of the potential transactions at 20.84GW is \$1708/h using the N–1 contingency criterion. At the ATC loading level of 19.4GW the security cost is \$876.3/h. Similar to the six-bus system, most jurisdictions would not allow the potential transactions to occur because of the ATC violation. However, the difference in security costs between the ATC and the potential transactions levels is only \$831.7/h which suggests that these transactions could be permitted in this particular example.

As indicated in Figure 4.7, there are several regions where the slope of the security cost profile changes significantly. The first of these regions is around the 26GW level. Numerous contingencies have thermal limits near this power level which increases the security cost. This phenomenon occurs again at approximately 40GW where a large number of bus voltage limits are exceeded, and then at approximately 45GW where voltage stability limits tend to aggregate. For this system, the change in slope of the security cost profile at power levels where multiple security limit violations tend to aggregate is clear; this characteristic may be useful as an indicator for operators to set transaction limits for this particular system as opposed to simply using the ATC or other similar security indices.

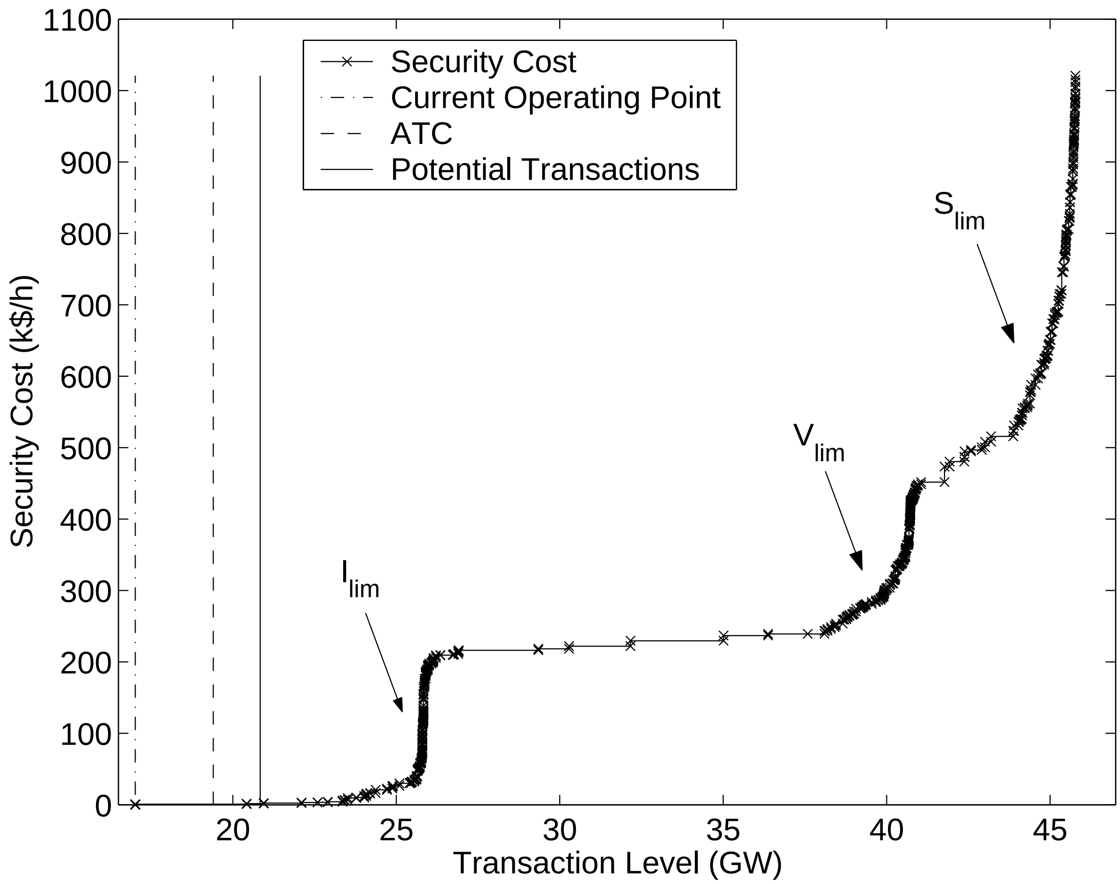

Figure 4.7: 129–bus Italian system model under N–1.

Table 4.5: Sample of the TSC Results for the 129-bus Italian System

Bus	Value of Transactions at MCP ($/h)	TCF	TSC (N–1) ($/h)	TSC (N–1) (%)
1	26463.85	0.106	180.94	0.68
11	17008.67	0.0	0.0	0.0
19	50967.04	0.0172	29.39	0.06
30	10509.89	0.005	9.09	0.09
32	28992.66	0.109	187.01	0.65
68	6467.20	0.003	5.69	0.09
101	3919.94	0.002	3.48	0.09
108	6063.00	0.0	0.0	0.0
120	18189.00	0.067	114.70	0.63

4.3.3 Transaction Results

A sample of TSC results for selected buses along with their corresponding TCF values are presented in Table 4.5. For comparison purposes, the TSC results are compared with the total value of the transactions assuming a MCP for all transactions at each bus. As in the six-bus system, the TSC values are reasonable when measured against the total value of each transaction, again amounting to no more than 1% of the transaction cost. A complete listing of the TSC results and corresponding TCF values for the Italian system is presented in Appendix B.

4.4 Discussion and Summary

In this chapter, the proposed security cost analysis methods are applied to two systems; a six-bus test system and a 129-bus model of the Italian system. In both cases, it is shown that there are risks of security violations when the system is operated at deterministic security indices such as the ATC. Although in these examples the security cost associated with the ATC is small, in both systems there is only a small increase in the security costs if the potential transactions are permitted to occur. In market environments, it may be reasonable to allow transaction levels to exceed the ATC in these systems if the associated security costs are deemed sufficiently small, as this cost reflects a low risk of security limit violations.

The security costs for both systems are distributed among all participants in the system consistent with the impact of their transactions on the ATC. All participants are included in the TSC analysis, including generators and consumers that are only part of the base loading conditions and are not bidding directly in the market. It is necessary to include all parties since ultimately, every participant has an affect the ATC and should be responsible for the associated security costs.

In the systems studied, there are noticeable increases in the slope of the security cost profiles at higher loading levels. The slope of the security cost profile may be a useful indicator for setting transaction limits for these particular systems. However, this subject is beyond the scope of this thesis and would be the subject of future research.

Chapter 5

Conclusions

5.1 Summary

The main goal of this thesis is to present a comprehensive framework for security cost analysis of power systems in competitive electricity markets. Using probability theory to incorporate the uncertainty of transmission line contingencies facilitates an understanding of the risks faced by operators. The two main components of this framework are an assessment of the bulk security cost and the distribution of those costs using sensitivity analysis.

Basic concepts in voltage stability are reviewed, as well as relevant bifurcations used in voltage stability analysis. These voltage stability limits as well as bus voltage limits and thermal limits are used to establish the loading margins, which in turn form the security limits for the system. Security limits are used to establish the security cost profile for the system as well as to establish the ATC under the

N–1 contingency criterion.

The security cost analysis considers the risk of contingencies occurring that will lead to security limit violations. It is assumed that transmission contingencies are Poisson distributed and that the time interval of interest is a bidding period in an electricity market, which is set to one hour. The average number of contingencies for the system is based on reliability data for transmission lines. A dollar-based cost function is used for the severity term in the risk evaluation, which establishes the bulk security cost for the system.

The security cost is then distributed among the participants based on the impact of the participants' transactions on the ATC. Sensitivity analysis is used to quantify this impact. Since a uniform pricing scheme is assumed for the market structure to which this method is applied, this TSC is an adjustment required for maintaining security. Recall that the ATC is not used to limit transaction levels, rather it is used in the sensitivity analysis to determine the *impact* of transactions on the ATC.

The methods presented are applied to two systems: a six-bus test system and a 129-bus model of the Italian HV system. The bulk security cost results indicate that for these systems, in some cases it may be reasonable to allow the ATC to be exceeded as long as the risk is deemed sufficiently low. Additionally, TSC values are presented for both systems and they are shown to be reasonably small when compared to the total transaction value.

5.2 Contributions

The purpose of this thesis is to extend the work done on a "take-risk" strategy developed by Chen in [19] and [20]. The "take-risk" strategy suggests that the costs associated with operating a system increase as the ATC is exceeded. This thesis attempts to validate this argument by including the probability of uncertainties in the system.

The security cost function in [19] is represented by a simple, fixed collapse cost. However, the techniques proposed in this thesis offer a more generic implementation of security cost to accommodate different types of security limit violations, similar to the techniques presented in [11]. Therefore, it is possible to tailor the security cost evaluation to the unique requirements of a given system, and make the cost analysis as simple or sophisticated as desired. Furthermore, the results presented for the example systems indicate that it may be possible to use the security cost profile or "curve" for operating purposes. This may prove to be a useful technique for determining transaction security limits instead of using deterministic criteria.

The proposed technique includes a sensitivity analysis of *all* transactions in a system when doing the transaction impact evaluation on the ATC. This is an extension of the technique in [20] which only looks at the impact of transactions cleared in the market. Including the impact of participants that are not bidding directly in the market facilitates an equitable distribution of security costs.

The bulk of the techniques proposed in this thesis have also been submitted for publication in [37] and [38].

5.3 Future Work

In this thesis, transmission contingency uncertainty is included in the security cost analysis. However, incorporating additional types of contingencies may facilitate a more accurate cost assessment at the expense of increased complexity. It would be interesting to see the effects of these additional contingencies on the security cost framework proposed in this thesis.

In the examples presented here, there is also potential for the application of the security cost profile to establish system transaction limits. The noticeable change in the slope of the profile near power levels where security limits tend to aggregate may be a possible indicator for setting these transaction limits.

The cost function of (4.1) used in the examples in this thesis is a simple, discrete function for illustrative purposes. It may be possible to create a more sophisticated representation of costs to better reflect system conditions. The effects of this cost function on the security cost analysis is an area worth exploring.

Finally, the contingency analysis in the security cost evaluation is computationally expensive since it is necessary to perform a CPF evaluation for all contingencies under consideration. However, future research on this topic may find ways to reduce the computational burden, thus making the proposed techniques more suitable for larger systems.

Appendix A

Six-bus System Data File

The data file for the six-bus system in WSCC format is below.

```
C*********************************************************************
C                           TITLE
C
HDG
  UWPFLOW data file, WSCC format
  6-bus  example : normal state
  December 2000
BAS
C
C*********************************************************************
C
C                         AC BUSSES
C
C                             | SHUNT |
C  |Ow|Name   |kV |Z|PL  |QL  |MW |Mva|PM |PG  |QM  |Qm  |Vpu
BQ  1 GENCO 1  230 1    0    0   0   0   089.87  150 -1501.05
BQ  1 GENCO 2  230 2    0    0   0   0   0  140  150 -1501.05
BQ  1 GENCO 3  230 3    0    0   0   0   0   60  150 -1501.05
B   1 ESCO 1   230 4   90   60   0   0   0    0    0    00.9754
```

```
B   1 ESCO 2   230 5  100   70   0   0   0    0    0    00.9677
B   1 ESCO 3   230 6   90   60   0   0   0    0    0    00.9930
C
C**********************************************************************
C
C                         AC LINES
C
C                 M            CS    N
C  |Ow|Name_1 |kV1||Name_2 |kV2|||In || R   | X   | G/2 | B/2 |Mil|
L   1 GENCO 1  230 GENCO 2  2301 65  1 .1    .2    0.0  0.02
L   1 GENCO 1  230 ESCO 1   2301 221 1 .05   .2    0.0  0.02
L   1 GENCO 1  230 ESCO 2   2301 200 1 .08   .3    0.0  0.03
L   1 GENCO 2  230 GENCO 3  2301 77  1 .05   .25   0.0  0.03
L   1 GENCO 2  230 ESCO 1   2301 340 1 .05   .1    0.0  0.01
L   1 GENCO 2  230 ESCO 2   2301 169 1 .1    .3    0.0  0.02
L   1 GENCO 2  230 ESCO 3   2301 221 1 .07   .2    0.0  0.025
L   1 GENCO 3  230 ESCO 2   2301 149 1 .12   .26   0.0  0.025
L   1 GENCO 3  230 ESCO 3   2301 343 1 .02   .1    0.0  0.01
L   1 ESCO 1   230 ESCO 2   2301 44  1 .2    .4    0.0  0.04
L   1 ESCO 2   230 ESCO 3   2301 50  1 .1    .3    0.0  0.03
C
C**********************************************************************
C
C                         SOLUTION CONTROL CARD
C
C        1         2         3         4         5         6         7         8
C 34567890123456789012345678901234567890123456789012345678901234567890123456789 0
C                     |Max|  |SLACK BUS |
C                     |Itr|  |Name   |kV|   |Angle    |
SOL                      50  GENCO 1  230       0.
END
```

Appendix B

Italian System Results

Complete TCF and TSC results for the Italian system are listed in Table B.1, and ATC results are shown in Table B.2 along with average failure rate, γ.

Table B.1: TSC Results for the Italian System

Bus	TCF	TSC ($/h)	Bus	TCF	TSC ($/h)
1	0.105927499	180.9364433	66	0	0
2	0.002552759	4.360408082	67	1.43043E-05	0.024433321
3	0.049482546	84.52192317	68	0.003332769	5.692754997
4	0.002787495	4.761365148	69	0.002441846	4.170955869
5	-0.003246494	0	70	0.01006372	17.19000045
6	-0.00432085	0	71	0.010760943	18.3809369
7	0.035375883	60.42610762	72	0.008555172	14.61322481
8	-0.001999661	0	73	0	0

Table B.1: TSC Results for the Italian System (cont.)

Bus	TCF	TSC ($/h)	Bus	TCF	TSC ($/h)
9	-0.005331932	0	74	0.003437957	5.872428661
10	-0.004234059	0	75	0	0
11	-0.008840708	0	76	0.004897752	8.365927396
12	0.002921491	4.990244805	77	0.004525329	7.729786563
13	0.154586677	264.0519589	78	0.003569805	6.09764071
14	0.001632702	2.788844336	79	0.003786157	6.467194692
15	0.000127638	0.218020404	80	0.002578163	4.403800721
16	-0.004510087	0	81	0.002013843	3.439877487
17	-0.00358647	0	82	0	0
18	-0.014734427	0	83	0.010601239	18.10814514
19	0.017208138	29.39349418	84	0.003916431	6.689718032
20	0.006154599	10.51276847	85	0.006923258	11.82572744
21	-0.006804736	0	86	0.000927943	1.585033398
22	0.000365553	0.624407096	87	-0.003928979	0
23	-0.004205372	0	88	0.00423532	7.234416639
24	0.001701228	2.905894563	89	0.006417175	10.96127862
25	-0.004351328	0	90	0.002001344	3.418527046
26	0.006693125	11.43263289	91	0.004048103	6.914629886
27	0.00423532	7.234416639	92	0.005949675	10.16273452

Table B.1: TSC Results for the Italian System (cont.)

Bus	TCF	TSC ($/h)	Bus	TCF	TSC ($/h)
28	0.005199898	8.882029097	93	0.004020568	6.867595743
29	0.006148518	10.50238117	94	0.00089382	1.526748441
30	0.005322722	9.091826749	95	-0.003974932	0
31	0.002881051	4.921168465	96	0.001555056	2.656215257
32	0.109480792	187.0058792	97	0.005076622	8.671458768
33	0.001142873	1.95215971	98	0.001644579	2.809132346
34	0.081452289	139.129948	99	0.004615446	7.883716486
35	0.003774512	6.447303463	100	0.004561447	7.791480699
36	0.005291125	9.037854169	101	0.002037283	3.479915765
37	0.006613773	11.29709061	102	0.00171651	2.931998538
38	0.004808405	8.213313113	103	0.004723622	8.068493477
39	0.004004109	6.839481761	104	0.004579506	7.822327767
40	0	0	105	0.004741681	8.099340545
41	0.004381035	7.483315436	106	0.003896857	6.65628406
42	0.00598817	10.22848782	107	0.001984238	3.389308866
43	0	0	108	-0.002882055	0
44	0	0	109	0.001616747	2.761591786
45	0	0	110	0.008365663	14.28952246
46	0.002596222	4.434647789	111	0.007382437	12.61005793

Table B.1: TSC Results for the Italian System (cont.)

Bus	TCF	TSC ($/h)	Bus	TCF	TSC ($/h)
47	0.002884263	4.926655521	112	0.001716021	2.931163211
48	0.001911048	3.264291706	113	0.002992807	5.112061618
49	0.006003674	10.2549703	114	0.007572314	12.93438938
50	0	0	115	0.000974691	1.664885459
51	0.003970958	6.782857017	116	0	0
52	0	0	117	0.001984795	3.39025905
53	0.004615446	7.883716486	118	0.004254244	7.266741192
54	0.001701839	2.906938722	119	0.004731628	8.08216935
55	-2.8364E-05	0	120	0.067149182	114.6985846
56	0.003488771	5.959224379	121	0	0
57	0	0	122	0.003022843	5.163366372
58	0.006274114	10.71691409	123	0.001876987	3.206111165
59	0.004451019	7.602855982	124	0.006059612	10.35051869
60	0.005880918	10.04529012	125	0.006363638	10.86983118
61	0.008221369	14.04305133	126	0.001914569	3.270306062
62	0.008582015	14.65907644	127	0.003768098	6.436347624
63	0.00893767	15.26657599	128	0.00317322	5.420226881
64	0.001063267	1.816184102	129	-0.000166284	0
65	0.005210503	8.900142646			

Table B.2: ATC Evaluation for the Italian System

Branch	γ (fails./yr.)	TTC (MW)	TRM (MW)
26 – 28	0.34734054	26072.63	1303.63
26 – 29	0.233918243	17016	850.8
26 – 30	0.388806757	25901	1295.05
27 – 3	0.428563589	24018.04	1200.9
27 – 35	0.248309459	26004.2	1300.21
27 – 36	0.397587838	24714.49	1235.72
28 – 29	0.428809459	25935.02	1296.75
28 – 4	0.482713589	25866.59	1293.33
29 – 31	0.246480263	25969.04	1298.45
29 – 33	0.246480263	17016	850.8
33 – 34	0.246480263	17016	850.8
31 – 30	0.246480263	17016	850.8
30 – 3	0.143668243	17016	850.8
30 – 32	0.143668243	17016	850.8
30 – 50	0.494667567	26897.14	1344.86
2 – 35	0.929089113	24365.88	1218.29
2 – 60	0.580768994	25621.57	1281.08
2 – 62	0.684924324	17016	850.8
2 – 109	0.684924324	25726.69	1286.33

Table B.2: ATC Evaluation for the Italian System (cont.)

Branch	γ (fails./yr.)	TTC (MW)	TRM (MW)
109 – 108	0.176841216	17016	850.8
109 – 60	0.176841216	25655.59	1282.78
4 – 35	0.530767567	24074.23	1203.71
36 – 38	0.088420413	17016	850.8
38 – 37	0.088420413	17016	850.8
36 – 39	0.205135811	24088.37	1204.42
39 – 6	0.205135811	24891.48	1244.57
36 – 50	**0.17586554**	**20421.88**	**1021.09**
37 – 123	0.155213609	22904.55	1145.23
123 – 122	0.155213609	22100.68	1105.03
122 – 121	0.155213609	20946.28	1047.31
37 – 125	0.145253521	26731.62	1336.58
125 – 12	0.145253521	25762.62	1288.13
37 – 50	0.14220473	26897.52	1344.88
37 – 51	0.186597973	17016	850.8
37 – 124	0.186597973	17016	850.8
124 – 129	0.186597973	17016	850.8
40 – 41	0.257456224	25727.45	1286.37
41 – 46	0.257456224	26004.97	1300.25

Table B.2: ATC Evaluation for the Italian System (cont.)

Branch	γ (fails./yr.)	TTC (MW)	TRM (MW)
40 – 49	0.157327703	25657.12	1282.86
40 – 65	0.804444594	25900.23	1295.01
43 – 9	0.049930398	17016	850.8
43 – 44	0.024965199	25831.81	1291.59
43 – 45	0.024965199	25831.81	1291.59
44 – 5	0.024965199	25831.81	1291.59
45 – 5	0.024965199	25831.81	1291.59
46 – 128	0.098787162	25901.38	1295.07
128 – 127	0.098787162	26108.56	1305.43
127 – 47	0.098787162	26349.37	1317.47
46 – 48	0.139521622	25831.43	1291.57
46 – 8	0.628577102	17016	850.8
47 – 126	0.140741216	25480.14	1274.01
126 – 9	0.140741216	25409.42	1270.47
47 – 51	0.226356757	17016	850.8
6 – 49	0.161962162	24193.49	1209.67
121 – 119	0.230137695	26907.08	1345.35
119 – 50	0.230137695	17016	850.8
48 – 9	0.391979654	26139.14	1306.96

Table B.2: ATC Evaluation for the Italian System (cont.)

Branch	γ (fails./yr.)	TTC (MW)	TRM (MW)
48 – 100	0.216356081	25969.42	1298.47
100 – 101	0.216356081	25797.02	1289.85
101 – 53	0.216356081	25692.29	1284.61
8 – 11	0.084152027	25832.96	1291.65
8 – 53	0.263188513	25797.79	1289.89
8 – 104	0.429541216	25831.43	1291.57
104 – 59	0.429541216	25761.47	1288.07
49 – 12	0.278311486	26905.55	1345.28
49 – 62	0.419786411	26140.67	1307.03
11 – 61	0.407586562	26122.7	1306.14
12 – 42	0.241113656	25623.48	1281.17
42 – 51	0.241113656	25901	1295.05
52 – 97	0.253675676	25610.1	1280.51
97 – 53	0.253675676	25687.7	1284.39
52 – 15	0.27075	25797.41	1289.87
52 – 96	0.135375	25797.41	1289.87
96 – 15	0.135375	25797.02	1289.85
52 – 56	0.065735953	25757.65	1287.88
53 – 103	0.348011415	17016	850.8

Table B.2: ATC Evaluation for the Italian System (cont.)

Branch	γ (fails./yr.)	TTC (MW)	TRM (MW)
103 – 102	0.348011415	25796.26	1289.81
102 – 99	0.348011415	25795.5	1289.78
99 – 54	0.348011415	25719.05	1285.95
54 – 55	0.176353378	17016	850.8
55 – 95	0.176353378	17016	850.8
54 – 98	0.191964189	25796.64	1289.83
98 – 56	0.191964189	25795.11	1289.76
15 – 94	0.180012162	23423.64	1171.18
15 – 59	0.360024324	23354.07	1167.7
94 – 59	0.180012162	23772.25	1188.61
57 – 58	0.255383108	25833.34	1291.67
57 – 61	0.321972973	25557.35	1277.87
58 – 63	0.082932432	25831.81	1291.59
58 – 106	0.041466216	25831.81	1291.59
106 – 63	0.041466216	25797.02	1289.85
58 – 64	0.709804054	25832.96	1291.65
59 – 105	0.382099181	25965.6	1298.28
105 – 61	0.382099181	25865.83	1293.29
59 – 93	0.157010413	25829.13	1291.46

Table B.2: ATC Evaluation for the Italian System (cont.)

Branch	γ (fails./yr.)	TTC (MW)	TRM (MW)
59 – 67	0.314021216	25830.28	1291.51
93 – 67	0.157010413	25831.04	1291.55
60 – 63	0.105275405	25449.18	1272.46
61 – 65	0.162206081	17016	850.8
62 – 110	0.204038371	25655.97	1282.8
110 – 65	0.204038371	25901	1295.05
63 – 64	0.62052973	25867.74	1293.39
63 – 70	1.77329054	25832.19	1291.61
64 – 69	0.411906854	25903.67	1295.18
66 – 69	0.100616749	25794.73	1289.74
66 – 71	0.55686494	24880.77	1244.04
66 – 72	0.013415541	25769.88	1288.49
67 – 92	0.527106832	23514.23	1175.71
92 – 91	0.527106832	25968.27	1298.41
91 – 77	0.527106832	25804.67	1290.23
68 – 71	0.148692973	25792.82	1289.64
68 – 76	0.308313513	25794.35	1289.72
68 – 112	0.200013513	25794.73	1289.74
68 – 80	0.400027027	25795.11	1289.76

Table B.2: ATC Evaluation for the Italian System (cont.)

Branch	γ (fails./yr.)	TTC (MW)	TRM (MW)
112 – 80	0.200013513	25795.88	1289.79
69 – 76	0.483814151	25780.59	1289.03
69 – 77	1.530101426	25648.33	1282.42
70 – 72	0.506617643	25823.78	1291.19
70 – 107	0.033953514	25797.41	1289.87
107 – 76	0.305581622	25832.19	1291.61
71 – 111	0.059028378	25796.26	1289.81
111 – 72	0.531255405	25788.23	1289.41
22 – 73	0.021647902	17016	850.8
76 – 23	0.799566216	25795.11	1289.76
77 – 90	0.537476313	25865.06	1293.25
90 – 79	0.537476313	25834.48	1291.72
78 – 79	0.626871621	25797.02	1289.85
78 – 23	0.434175676	25792.82	1289.64
78 – 85	0.210258108	25831.43	1291.57
74 – 73	0.017927845	25795.11	1289.76
74 – 75	0.157498641	17016	850.8
74 – 89	0.787491254	25796.26	1289.81
89 – 79	0.787491254	25834.1	1291.71

Table B.2: ATC Evaluation for the Italian System (cont.)

Branch	γ (fails./yr.)	TTC (MW)	TRM (MW)
74 – 86	0.357585135	25831.81	1291.59
73 – 118	0.827251208	25798.55	1289.93
118 – 79	0.827251208	25799.7	1289.99
73 – 82	0.753709459	25832.19	1291.61
73 – 88	0.429785135	25831.43	1291.57
88 – 86	0.429785135	25831.81	1291.59
80 – 23	0.194403378	25824.93	1291.25
80 – 113	0.11396126	25795.11	1289.76
113 – 85	0.11396126	25831.04	1291.55
80 – 114	0.11396126	25793.58	1289.68
114 – 85	0.11396126	25831.81	1291.59
81 – 82	0.743952702	25833.72	1291.69
81 – 83	0.399172335	25810.02	1290.5
81 – 24	0.242211486	17016	850.8
82 – 86	0.427345946	25832.19	1291.61
83 – 85	0.46905413	25799.7	1289.99
84 – 115	0.66431298	17016	850.8
115 – 24	0.66431298	17016	850.8
84 – 87	0.497840465	17016	850.8

Table B.2: ATC Evaluation for the Italian System (cont.)

Branch	γ (fails./yr.)	TTC (MW)	TRM (MW)
25 – 117	0.442468919	17016	850.8
117 – 116	0.442468919	17016	850.8
116 – 87	0.442468919	17016	850.8
28 – 1	0.410513589	17016	850.8
121 – 7	0.010732432	17016	850.8
121 – 120	0.010732432	17016	850.8
49 – 10	0.030977703	17016	850.8
50 – 13	0.001524396	17016	850.8
52 – 14	0.097811486	17016	850.8
55 – 16	0.090006081	17016	850.8
57 – 17	0.004329658	17016	850.8
64 – 18	0.057199182	17016	850.8
66 – 19	0.013825324	17016	850.8
69 – 20	0.010595838	17016	850.8
72 – 21	0.023106342	17016	850.8

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Glossary

ATC	Available Transfer Capability
CBM	Capacity Benefit Margin
CESI	Italian Electrical Research Center
CPF	Continuation Power Flow
ESCO	Energy Supply Company
ETC	Existing Transmission Commitments
GENCO	Generation Company
HV	High Voltage
ISO	Independent System Operator
LIB	Limit-induced Bifurcation
LMP	Locational Marginal Price
LOEE	Loss of Energy Expectation

LOLP	Loss of Load Probability
MCP	Market Clearing Price
MVN	Multi-variate Normal (Distribution)
OPF	Optimal Power Flow
S.V.	Security Violation
SLIB	Saddle Limit-induced Bifurcation
SNB	Saddle-node Bifurcation
TCF	Transaction Contribution Factor
TI	Transaction Impact
TRM	Transfer Reliability Margin
TSC	Transaction Security Cost
TTC	Total Transfer Capability
WECC	Western Electricity Coordinating Council