MULTI-AREA NETWORK ANALYSIS

A Dissertation

by

LIANG ZHAO

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

DOCTOR OF PHILOSOPHY

December 2004

Major Subject: Electrical Engineering

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ABSTRACT

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After the deregulation of the power systems, the large-scale power systems may contain several areas. Each area has its own control center and each control center may have its own state estimator which processes the measurements received from its local substations. When scheduling power transactions, which involve several control areas a system-wide state estimation solution is needed. In this dissertation, an estimation approach which coordinates locally obtained decentralized estimates while improving bad data processing capability at the area boundaries is presented. It is assumed that synchronized phasor measurements from different area buses are available in addition to the conventional measurements provided by the substation remote terminal units. The estimator with hierarchical structure is implemented and tested using different measurement configurations for two systems having 118 and 4520 buses. Furthermore, we apply this multi-area solution scheme to the problem of Total Transfer Capability (TTC) calculation. In a restructured power system, the sellers and buyers of power transactions may be located in different areas. Computation of TTC will then require system-wide studies. We investigate a multi-area solution scheme, which takes advantage of the system-wide calculated Power Transfer Distribution Factors (PTDF) in order for each area to calculate its own TTC while a central entity coordinates these results to determine the final value. The proposed problem formulation and its solution algorithm are presented. 30 and 4520 bus test systems are used to demonstrate the approach and numerically verify the proposed TTC calculation method.

To my family: my mother, father and brother

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CHAPTER I

INTRODUCTION

1.1 Motivation

Modern power systems are now stepping into the post-restructuring era, in which electric power industry has unbundled the energy generation, transmission, distribution and reliability service previously supplied by vertically integrated utilities. Federal Energy Regulator Commission (FERC) order No. 888 [1] and 889 [2] enable that the entities that can supply the reliable electric service to compete to provide these services in wholesale power markets. In December 1999, following the initial creation of several Independent System Operators (ISOs), FERC issued Order No. 2000 [3] to require owners of transmission systems form or join Regional Transmission Organizations.

The old integrated utilities now have been divided into a more complex system with several new and often independent entities: operators of generating facilities, purchases of wholesale electricity, non-profit or for profit operators of transmission grid and traders in various energy, transmission and capacity products [4]-[21]. In such a decentralized environment, the interpretation of price signals becomes one of the primary business tasks of market participants. This task is much more complex than the unit-commitment, transmission planning, economic dispatch and generation planning problem of old utility: to the difficulties associated with anticipating uncertain future events are added to the problems of anticipating the behavior of the other players.

Furthermore, the traditional integrated large-scale power transmission system has been changed into an unbundled power system, which contains transmission, distribution and

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generation sub-systems. The transmission system may cover several control areas. Each area is under the supervision of Independent System Operator (ISO). It is a challenging task to manage a very large-scale power system with several areas. It is necessary to have a central entity to monitor and control the overall system so that the power transactions between different local areas can be managed without congestion or compromising system security. On the other hand, huge size of the interconnected system with several areas makes this kind of task very difficult. Based on commercial and/or technical requirements, there may be limited or no information exchange (such as measurements, load and generation within the area) between individual areas. Then, a good compromise would be for the individual area to manage its own system operation and to have the central entity to coordinate system operation of the overall system. This requires a control center, which has a hierarchical structure.

Hierarchical structure is not a new concept. T.E. Dy-Liacco mentions a control center [22], which has hierarchical structure: each area has its own control center and the central entity coordinates the system operation of overall system. Two level structure concept is also studied in several power system applications, such as power flow, state estimation [23]-[26] OPF, ATC and TTC calculations [27]-[32]. In all these studies, researchers focus mainly on the reduction in computing time, memory requirements and data exchange between areas.

This dissertation presents the State Estimation and TTC calculation with hierarchical structure in very large-scale power systems, which contain several areas. State Estimation constitutes the core of the on-line system security analysis and acts like a filter between the raw information received for the system and all application functions that need the reliable data for the current state of the system. Total Transfer Capability (TTC) is an important indicator of how much power can be exchanged between two points in the system without compromising system security.

1.2 Objectives

The dissertation is mainly focused on the large-scale power system operation, which may contain several areas. After the deregulation of the power systems, operators are faced with the need to monitor and coordinate power transactions taking place over large distances in remote parts of the power system. In a large-scale power system, which may contain several areas, each area will have its own control center. Each control center may carry out applications, such as power flow, state estimation, and TTC calculations for its own area. When scheduling power transactions, which involve several control areas, a system-wide solution is needed. Such a solution may be obtained by a central application, which will collect wide area information and will solve the very large-scale application problem. However, the huge size of the interconnected system will make this task very difficult. Furthermore, the individual independent system operators (ISO) may be reluctant to modify their existing hardware and software in order to meet the new specifications imposed by the central application for the large-scale solution. Also, the ISOs may be unwilling to share the application data between each other. Then, a good compromise would be for the individual ISOs to keep their existing monitoring software and to have a central entity to coordinate their results to determine the overall system solution. In this study, two applications--state estimation and TTC calculation--are investigated. Novel approaches for state estimation and TTC calculation are introduced. These approaches are based on hierarchical structures and will be discussed in detail in the following chapters.

1.3 Contributions of the Dissertation

This study proposes a hierarchical structure to satisfy the special requirement of multi-area power system operation. This new structure allows local area control centers to keep their own applications and process their data independently. When the central entity receives the processed data from these local centers, it determines overall system solution. This dissertation explores how this new scheme is used in two specific applications, namely state estimation and total transfer capability calculation. The following contributions are achieved:

- A new solution scheme is designed for the multi-area state estimation problem by giving local area centers freedom to solve their own problems while a central entity integrating their results. That is to say, in each area, the control center keeps its own applications, and the central entity addresses the overall system solution based on the received results from each local area. As a result, the information exchange between the areas is avoided.
- In state estimation, through proper decomposition of the system, the boundary injection measurements, which are commonly ignored in previous studies, are used in the local as well as central coordinator state estimator.
- In state estimation, the bad data appearing at area boundaries can be detected and identified.
- Synchronized phasor measurements are used to improve measurement redundancy and to facilitate bad data detecting/identification at area boundaries.
- TTC calculation is carried out in a distributed manner, without requiring a large-scale integrated network solution. A new multi-area method that makes use of the Power Transfer Distribution Factor (PTDF) is developed for this purpose.

1.4 Outline of the Dissertation

The dissertation includes six chapters. Chapter I introduces the motivations, objectives, and contributions of the completed work. Chapter II analyzes the traditional state estimation problem—its definition, formulation, and its function in bad data detection. Furthermore, a new type measurement, phasor measurement, is introduced. At last some previous state estimation works, which have hierarchical structure, are reviewed. The previous work cannot satisfy the special requirement of the multi-area state estimation, and the need to have a new scheme to solve multi-area state estimation problem is addressed. Chapter III demonstrates the new designed state estimation in multi-area power system. This chapter specifies the decomposition of the system, formulation of the state estimation with hierarchical structure, and simulation results. In the hierarchical state estimation, the boundary injection measurements, which are normally ignored in previous work, are used in local area state estimation and coordinate level state estimation. The application of the synchronized phasor measurements is also elaborated. Chapter IV reviews the traditional TTC calculation, including the TTC problem definition, formulation, and TTC calculation method, and surveys a recent study addressing the hierarchical structure in TTC calculation. The chapter concludes that it is necessary to have a new scheme to solve the multi-area TTC calculation. Chapter V initiates a new designed scheme to solve the TTC calculation in multi-area power system, including the problem formulation, and solution of DC TTC and AC TTC in multi-area power system. The application of PTDFs is generated by central entity and used in TTC calculation on each area. Following a summary of the contributions of the completed work, Chapter VI offers suggestions for future research.

CHAPTER II

STATE ESTIMATION

In this chapter, the traditional state estimation problem is introduced, such as problem definition, formulation and bad data detection. Before presenting the main ideas of the dissertation, it is appropriate to provide a review of the state of act in the area of state estimation. The review will cover the Weighted Least Squares (WLS) method to solve the state estimation problem processing, as well as the commonly used chi-squares test and largest normalized residual test for bad data processing. We will also review previously proposed methods for hierarchical state estimation.

2.1 State Estimation Problem

State Estimation constitutes the core of the on-line system security analysis, and acts like a filter between the raw information received from the system and all application functions that need the reliable data for the current state (complex bus voltage phasors) of the system. In the power system control center, the measurement data are collected from the Supervisory Control and Data Acquisition (SCADA) system, but this kind of data is not always complete due to telemetry or transducer failures, further more this kind of data may include some bad data. On the other hand, a real-time AC power flow may not be extracted directly from the collected measurement data. State estimation is a tool, which is developed to solve these problems [33]. The function of the state estimation is to use the measurement data from SCADA as well as the information about the status of the circuit breakers, switches, transformer taps and the parameters of the transmission lines, transformers and shunt capacitors and reactors to estimate the state of the power system.

State Estimation process involves the following functions:

- Topology processing: obtains the on-line model of the system based on the information on the circuit break/switch statuses, transmission line and transformer parameters.
- Observability analysis: tests if there are sufficient measurements available to estimate the entire system state. If the test fails, then the pseudo-measurements will be added to enlarge the identified observable islands, until the entire system is observable [34]-[39].
- State estimation: finds out the estimated state of entire system by solving a non-linear optimization problem. When the state is estimated, estimates for other quantities, such as line flows and bus injections, can be computed.
- Bad data processing: checks the measurements for the existence of possible bad data. If any bad data are detected, they will be removed from measurement set and state estimation will be repeated [40][41].

In this dissertation, it will be assumed without loss of generality that the entire system is observable. This implies that the system has enough measurement redundancy to keep the system observable. Only state estimation solution algorithm and bad data processing problems will be addressed.

For the power system, the measurements can be of different types. The commonly used types are as follows:

- Power Flows: real and reactive power flows measured at the terminal buses of a transmission line or transformer.
- Power injections: real and reactive power injected at the system buses.
- Voltage magnitude: voltage magnitude measurements at system buses.
- Current magnitude: current flows along the transmission lines or transformers measured at the terminal buses. Only magnitude (Amps) is measured.
- Synchronized phasor measurement: voltage phasor measured at the system buses.

The measurements in the system are assumed to have the errors which have a Gaussian distribution with zero mean.

Consider a measurement i expressed in terms of the system state:

$$z_i = h_i(x) + e_i \qquad (2.1)$$

where:

z_i is the measured value of the ith measurement;

$h_i(x)$ is the nonlinear function relating error free measurement i to the state vector x;

$x^T = [x_1, x_2, \cdots, x_n]$ is the system state vector, including voltage magnitude and phase of all the system buses excluding the reference bus phase angle;

e_i is the measurement error, which is assumed to have a normal distribution with zero mean and known variance. Furthermore, the measurement errors are assumed to be independent, i.e. $E(e_i e_j) = 0$.

Hence, the covariance matrix of the measurement errors is diagonal and each diagonal entry is $\text{cov}(e_i) = E[e_i e_i] = R_{ii} = \delta_i^2$

where:

δ_i is the standard deviation of the measurement error which is calculated to reflect the expected accuracy of the corresponding meter used. Every measurement i will be assigned a weight W_{ii} based on its standard deviation as $W_{ii} = \delta_i^{-2}$

The residual for measurement i is defined as:

$$r_i = z_i - E(z_i) \qquad (2.2)$$

where $E(z_i) = h_i(\hat{x})$, $\hat{x}$ is the estimated state.

State estimation problem is formulated assuming a positive sequence model of the power system. This implies that power system is balanced, and the transmission lines are fully transposed and therefore the three phase system can be modeled by its single phase equivalent circuit.

2.2 State Estimation Problem Formulation

2.2.1 State Estimation

The commonly used Weighted Least Squares (WLS) state estimation problem can be formulated as the following optimization problem:

$$\text{Minimize } J(x) = \sum_{i=1}^{m} W_{ii} r_i^2 \tag{2.3}$$

Subject to $z_i = h_i(x) + r_i$, $\quad i = 1,2,\cdots m$

where

$z^T = [z_1, \cdots, z_m]$ is the measurement vector;

$h^T(x) = [h_1(x), \cdots, h_m(x)]$ is nonlinear measurement function vector;

$W^{-1} = R = diag\{R_{11}, \cdots, R_{mm}\} = diag\{\delta_1^2, \cdots, \delta_m^2\}$ is covariance matrix of measurements;

$x^T = [x_1, x_2, \cdots, x_n]$ is the state vector;

m: number of measurements;

n: number of states;

It is assumed that there are n states and m measurements in the power system.

In order to solve equation (2.3), the following first order optimality conditions must be satisfied:

$$g(x) = \frac{\partial J(x)}{\partial x} = -H^T(x) R^{-1} [z - h(x)] = 0 \tag{2.4}$$

where $H(x) = \dfrac{\partial h(x)}{\partial x}$

The nonlinear equation (2.4) can be solved by Newton’s method using the iterative procedue below:

$$x^{k+1} = x^k - (G(x^k))^{-1} g(x^k) \tag{2.5}$$

where

k is the iteration index;

$$G(x^k) = \frac{\partial g(x^k)}{\partial x} = H^T(x^k)R^{-1}H(x^k) \tag{2.6}$$

$$g(x^k) = -H^T(x^k)R^{-1}(z - h(x^k)) \tag{2.7}$$

$G(x)$ is called as "gain" matrix.

If the system is fully observable, the gain matrix will be positive definite. At each iteration, the gain matrix will be decomposed into its triangular factors, and forward/backward substitutions will be used to solve the following sparse linear set of equation:

$$G(x^k)\Delta x^{k+1} = H^T(x^k)R^{-1}[z - h(x^k)] \tag{2.8}$$

where $x^{k+1} = x^k + \Delta x^{k+1}$

2.2.2 Bad Data Detection

Sometimes, the measurements are not accurate due to meter, telemetery or other types of errors. After the WLS state estimation, the bad data detection and identification will be done by processing the measurement residuals.

The commonly used method to detect bad data is the Chi-squares test. When bad data are detected, the Largest Normalized Residual (r^N) test will be applied to identify the bad data. The details of the two methods will be illustrated in the following two sections.

2.2.3 Chi-Squares Test

Chi-squares test is based on the premise that the sum of squares of independent random variables, each distributed according to the standard normal distribution, will have a Chi-squares distribution. Then the WLS state estimator objective function J(x) can be shown to approximate a Chi-squares distribution with $(m-n)$ degrees of freedom. $(m-n)$ is the number of redundant measurements in the power system, m,n being the number of measurements and states respectively.

The steps of applying the Chi-squares test are given below:

- Solve the WLS state estimation, obtain the state estimate $\hat{x}$, and compute the objective function $J(x) = [z - h(\hat{x})]^T R^{-1}[z - h(\hat{x})]$.
- Look up the value C corresponding to p (e.g. 95%) probability and $(m-n)$ degrees of freedom from chi-squares distribution table. Here $p = \Pr(Y \le C)$, where Y is a random variable with $\chi^2_{m-n,p}$ distribution.
- Test if $J(\hat{x})) \le C$. If yes, then no bad data will be detected; otherwise, it will be suspected that there is bad data in the measurement set.

A simple case is shown in figure 1. Consider a 3-bus system. The number of state variables is (2*3-1)=5 (slcak bus phase angle being excluded from the state list). Assume that there are 10 measurements: 2 voltage magnitude measurements, 2 pair real/reactive power flow measurements and 2 pair real/reactive power injection measurements . The degree of freedom will be 10-5=5. Using 0.95 probability, the value found from the Chi-squares table will be $\chi^2_{5,0.95} = 11.07$. Hence, if the objective function $J(\hat{x}))$ evaluated at the WLS estimate $\hat{x}$, is larger than 11.07, bad data will be suspected in the measurement set.

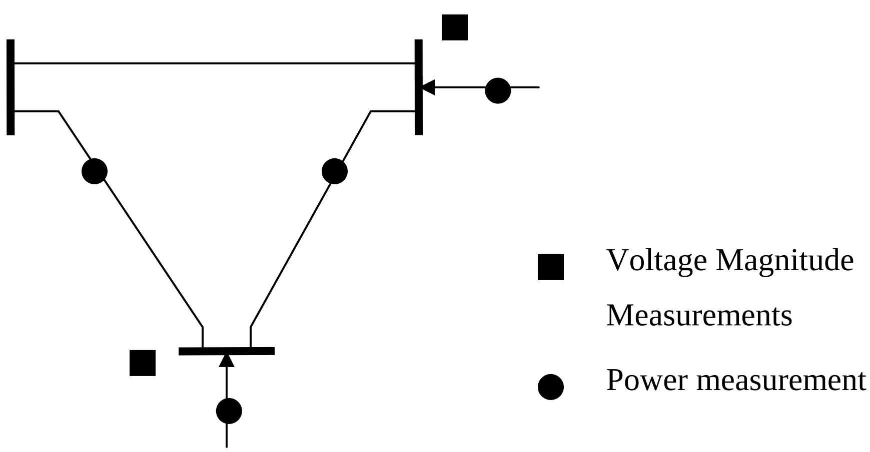

Figure 1. Simple Example for Chi-Squares Test

2.2.4 Largest Normalized Residual (r^N) Test

Before describing this test, the properties of measurement residuals will be briefly reviewed.

Consider the state estimate in the linearized measurement model:

$$\Delta \hat{x} = (H^T R^{-1} H)^{-1} H^T R^{-1} \Delta z \tag{2.9}$$

$$\Delta \hat{z} = H \Delta \hat{x} = K \Delta z \tag{2.10}$$

here $\Delta \hat{z}$ is the estimated value of Δz and $K = H(H^T R^{-1} H)^{-1} H^T R^{-1}$ is called the "hat matrix". It is noted that $KH = H$

Then the measurement residual can be expressed as below:

$$\begin{aligned} r &= \Delta z - \Delta \hat{z} \\ &= (I - K)\Delta z \\ &= (I - K)(H\Delta x + e) \\ &= (I - K)e \\ &= Se \end{aligned} \tag{2.11}$$

where S is called the residual sensitivity matrix. The covariance matrix for the residuals Ω, can then be calculated as:

$$\Omega = E[rr^T] = SE[ee^T]S^T = SRS^T = SR \tag{2.12}$$

Hence, the normalized value of the residual for the measurement i is:

$$r_i^N = \frac{r_i}{\sqrt{\Omega_{ii}}} = \frac{r_i}{\sqrt{R_{ii} S_{ii}}} \tag{2.13}$$

Next the steps of the largest normalized residual test will be presented:

- Solve the WLS state estimation problem and obtain the measurement residual vector $r = z - h(\hat{x})$.
- Compute the normalized residual: $r_i^N = \frac{r_i}{\sqrt{\Omega_{ii}}} = \frac{r_i}{\sqrt{R_{ii} S_{ii}}}$ for $i = 1, 2, \cdots, m$.
- Find the largest one r_k^N among all normalized residuals.

- If $r_k^N > c$, then the k-th measurement will be identified as the bad data. Otherwise, no bad data is detected. Here c is a threshhod, e.g. 3.0;
- Remove the bad data, and repeat the state estimation again.

2.3 Synchronized Phasor Measurement

Phasor measurement units (PMUs) use the synchronization signals received from the GPS satellite system. Figure 2 shows the functional block diagram of a PMU [42].

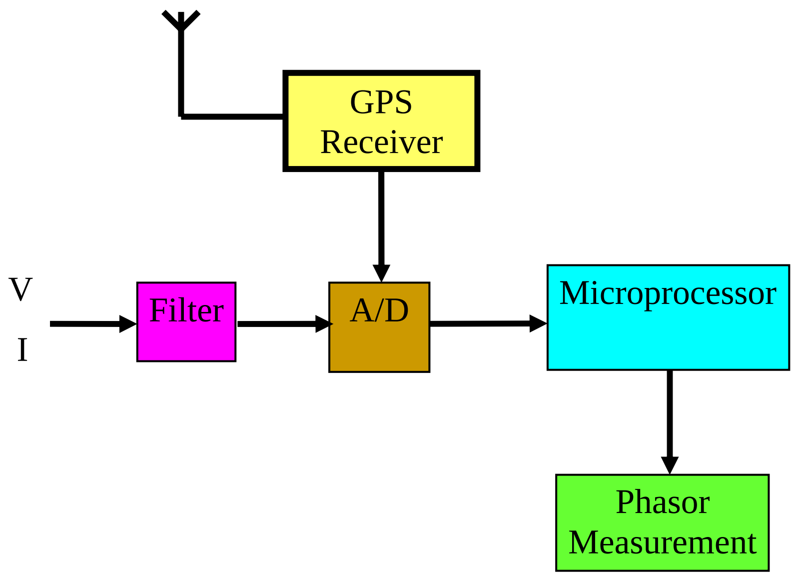

Figure 2 Phasor Measurement Unit

The GPS receiver provides the synchronization signal to A/D transformer, and the voltage or current analog signals are input into A/D transformer through an anti-aliasing and surge filter. The microprocessor determines the phasor of the voltage or current according to the digital signal from the A/D transformer.

PMUs have evolved into mature tools, and now are being commercially used in power system. Such measurements make significant improvements in control and protection functions at the substations [43]-[46]. Their benefits also extend to the state estimation function, as illustrated by the preliminary work reported in [47]-[50].

2.4 State Estimation with Hierarchical Structure

The use of hierarchical structure is not new. T.E. Dy-Liacco mentions a control center in [22], which has hierarchical structure. In this structure, each area has its own control center and a central entity coordinates the integrated system operation. Hierarchical concept has been used in large-scale power system power flow, OPF, TTC and ATC studies [27]-[32]. It has also been applied to the state estimation problem since 1970's [23]-[26]. The objective of previous work in this area is mainly to reduce the computing time, memory requirements and data exchange between areas in a large –scale power system.

Based on different decomposition schemes, or special requirements on such thing like accuracy (optimal or non-optimal), information exchange, computing time, etc., there are many different types of hierarchical schemes for state estimation. Some of these will be reviewed briefly next.

- Method of Clements et al. [23]: The network is partitioned into several regions. Each branch belongs to only one region. Thus, two adjacent regions have some boundary bus in common. The system is composed by boundary buses. The first level state estimation is a conventional state estimation, and its results will be fully used as pseudo-measurement in the second level state estimation and be corrected. Because there is no iteration between first level and second level, it is a global non-optimal method. This method can not use the injection measurements on the boundary buses because of the decomposition scheme. Bad data detection will be addressed in the first level easily.

- Method of Kobayashi et al. [24]: The network is supposed to be composed of several non-over-lapping areas connected by tie-lines. Each tie-line only belongs to one of two adjacent area. The first level state estimation is a normal state estimation. In second level state estimation, there are two steps: first step, estimate the boundary bus status; second step, using the results from first level state estimation and first step, estimate the overall system state (global optimization). The iteration is needed between the two levels. The injection measurements on the boundary buses have not been considered. But it would be possible to use them through modifying their algorithm at first step of second level state estimation. The algorithm is a little bit complex, and the bad data processing is very difficult, but it a global optimal solution.

- Method of Van Cutsem et al. [25]: The network is supposed to be composed of several non-over-lapping areas connected by tie-lines. The tie-lines do not belong to any area, so the flow measurements on tie-line can not be used in the first level state estimation. The first level state estimation is a conventional one and the state of boundary buses will be send to second level state estimation. In second level state estimation, the boundary bus states will be used as pseudo-measurements together with the tie-line flow measurements. There will be no iteration between two levels, and it is not a global optimal method. Because of the decomposition scheme, the injection measurements on the boundary buses can not be used.

- Method of Mukai et al. [26]: The network is composed by the topology of the network but by the measurement configuration (structure of gain matrix). It is specially designed for parallel calculating and reducing the computing time. Mathematically decomposed a large-scale optimization problem to several sub-problems, solve the sub-problems in parallel computers and coordinate the result in the central computer. Iteration is necessary between local level and central level. The method is global optimal and has fast computing speed. But the observability analysis and bad data detection will be very difficult.

2.5 Summary

In this chapter, the traditional state estimation and bad data processing are briefly introduced. The hierarchical structure is described as well as its application in state estimation. Some state estimation with hierarchical structure are briefly reviewed, their advantages and disadvantages are mentioned and compared.

In the deregulated power system, which may contain several areas, when scheduling power transactions, a system-wide state estimation solution is needed. Such a solution may be obtained by a central state estimator which will collect wide area measurements and will solve the very large scale state estimation problem. The fact that control areas are reluctant to share network and application data between them adds to this challenge. Then, a good compromise would be for the individual ISOs to run its own state estimator and to have a central entity to coordinate their results to determine the state of the overall system. In such a case, it is necessary to have a new scheme to solve the multi-area state estimation problem. As well, in the previous works, they have difficult to use the boundary injection measurements or even exclude these measurements in their scheme. In the new designed state estimator, all available measurements will be used, including the boundary injection measurements.

In next chapter, a newly designed state estimator with hierarchical structure, which can satisfy the special requirements of deregulated power system, will be introduced. Phasor measurements will be used in the coordinator state estimator and benefits gained through their utilization will be presented.

CHAPTER III

STATE ESTIMATION IN MULTI-AREA POWER SYSTEM

3.1 Introduction

This chapter will introduce a new approach to solve the large-scale system state estimation problem. The proposed system decomposition, formulation of the state estimation problem within this decomposed framework and finally the solution procedure will be described in detail. Simulation results will be given to demonstrate the proposed procedure.

After the deregulation of the power systems, operators are faced with the need to monitor and coordinate power transactions taking place over large distances in remote parts of the power grid. Real-time measurements are used for this purpose. State estimation (SE) function is the primary tool used at the control centers for the management of real-time data received from the substations. Each control center may have its own state estimator which processes the measurements received from its local substations. When scheduling power transactions, which involve several control areas, a system-wide state estimation solution is needed. Such a solution may be obtained by a central state estimator, which will collect wide area measurements and will solve the very large-scale state estimation problem. However, the huge size of the interconnected system will complicate this solution. Furthermore, the individual independent system operators (ISO) may be reluctant to modify their existing hardware and software in order to meet the new specifications imposed by the central state estimator for the large-scale solution. Then, a good compromise would be for the individual ISOs to keep their existing monitoring software and to have a central entity to coordinate their results to determine the state of the overall system. This chapter will introduce the design and implementation of such an estimation scheme, which involves independent local estimators and a central coordinator. The new scheme will use all available measurements including the injection measurements on boundary buses and try to reach a objective: available measurements to estimate the state, detect, and identify the bad data for integrated system, will also be applicable to state estimator with hierarchical structure.

Until very recently, the measurements used by the state estimators typically included voltage magnitudes, branch power flows, bus power injections and occasionally current magnitude measurements. However, nowadays it is also possible to have synchronized phasor measurements at the substations. Such measurements make significant improvements in control and protection functions at the substations. Their benefits also extend to the state estimation function.

It is assumed that each area has its own state estimator, which processes measurements from its own area. A central coordinator receives the results from individual area state estimators and the phasor measurements, along with the measurements from their boundaries, and then computes the system wide solution. The proposed algorithm does not impose any special requirements on the boundary measurements so that it can be applied to any multi-area measurement configuration. Furthermore, since individual area estimators do not interact or exchange data, each area can have its own special estimation algorithm, measurement, and network database without affecting the performance of the rest of the area estimators.

3.2 Multi-area System Decomposition

Let us consider a large power system containing N buses and n areas. Areas are separated by tie-lines whose terminal buses are assigned to both areas. This assignment of buses creates protruding boundaries, which include tie-lines and their remote end buses as shown in Figure 3.

This type of overlapping bus assignments for multiple areas can be found also in [24][25]. Based on this decomposition, in each area "i", a bus will belong to one of the following three categories:

Internal bus, all of whose neighbors belong to the area i.

Boundary bus, whose neighbors are area i internal buses and at least one boundary bus from another area.

External bus, which is a boundary bus of another area with a connection to at least one boundary bus in area i.

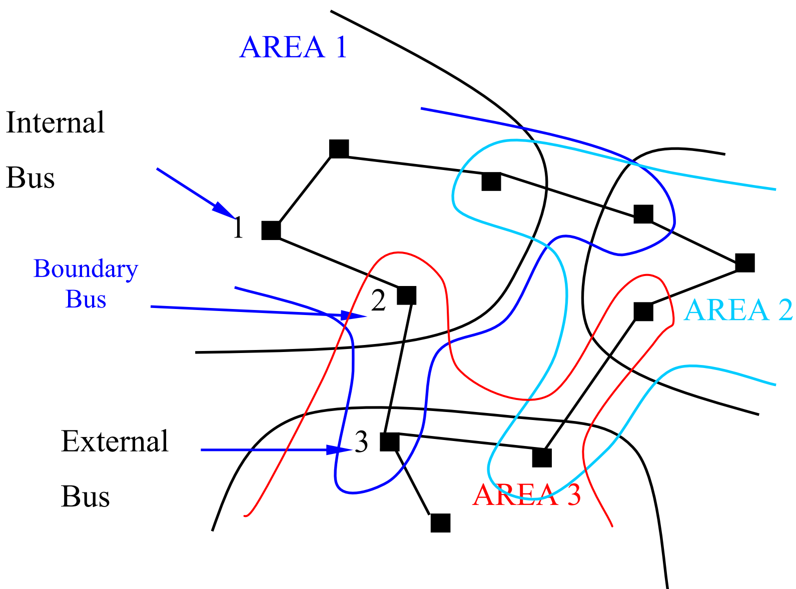

Figure 3. Overlapping Bus Assignments for Areas

In Figure 3, buses 1, 2 and 3 are examples of internal, boundary and external buses respectively for area 1. Similarly, state variables associated with these three different types of buses can be defined for area *i* ($i = 1,2,\cdots,n$) as follows:

The vector x_i^b consisting of the voltage magnitudes and phase angles at the boundary buses of area *i*.

The vector x_i^{int} consisting of the voltage magnitudes and phase angles at the internal buses of area *i*.

The vector x_i^{ext} consisting of the voltage magnitudes and phase angles at the external buses of area *i*.

The phase angle of the chosen slack bus for the area will be excluded from the appropriate vector x_i^b, x_i^{int} or x_i^{ext}. Thus, the state vector for area *i* will be given by:

$$x_i \overset{\Delta}{=} \left[x_i^{b^T}, x_i^{\text{int}^T}, x_i^{ext^T}\right]^T$$

whose dimension is n_i. As evident from the above definitions, each area state vector includes not only the states of that area but also part of the states belonging to its immediate neighbors. Hence, some of the states will be estimated simultaneously by two neighboring area estimators in the local level where individual areas independently execute their state estimators based on their measurements. The types of measurements used by each area estimator at this level will be discussed in detail in the next section. Next we turn our attention to the coordination level, where a single central entity receives state estimation results from each area as well as certain extra measurements and calculates the system wide state estimation solution.

At this level, the state estimator will essentially be coordinating the individual area estimates and also perhaps more importantly, will ensure that all bad data associated with the boundary measurements will be identified and corrected. The states, which are to be estimated in this level, will be defined as:

$$x_S \overset{\Delta}{=} \left[x^{b^T}, u^T\right]^T$$

where:

$$x^b \overset{\Delta}{=} \left[x_1^{b^T}, x_2^{b^T}, \cdots, x_n^{b^T}\right]^T$$

$$u \overset{\Delta}{=} [u_2, u_3 \cdots, u_n]$$

u_i is the phase angle of the slack bus of the *ith* area with respect to the slack bus of area 1. Area 1 is arbitrarily chosen to be the reference area with $u_1 = 0$.

The above-described two-level framework will now be used to formulate the multi-area state estimation problem. The objective of this formulation will be to allow each area estimator to remain completely independent in the local level and have the results be coordinated by an independent and central entity in the coordinate level.

3.3 Formulation of the State Estimation Problem

3.3.1 Required Exchange of Data and Measurements

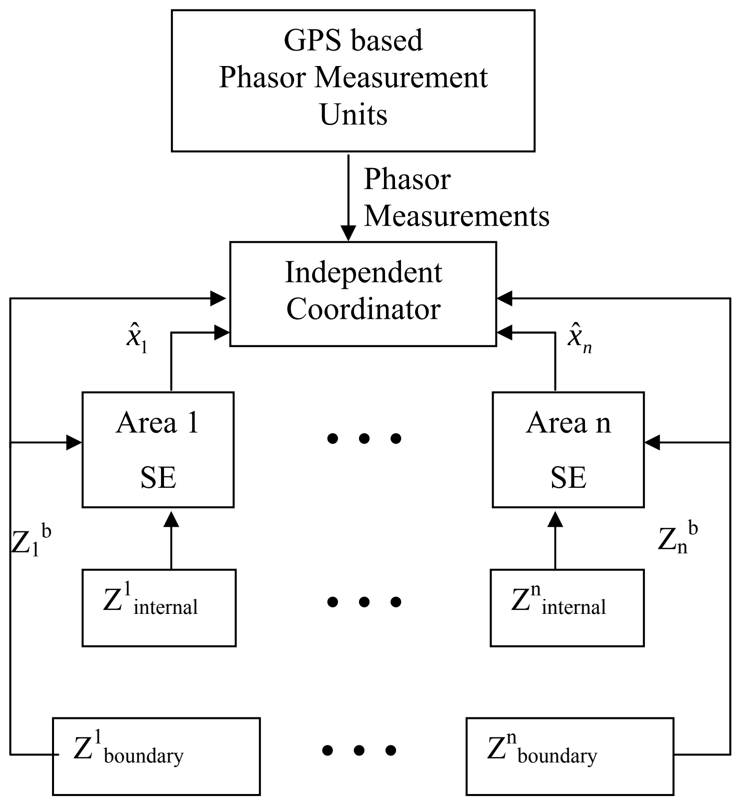

Figure 4. Data and Measurement Exchange

A diagram of the required data and measurement exchanges for the proposed implementation of the multi-area state estimator is shown in Figure 4. As illustrated in the figure, each area has its own state estimator, which will process locally acquired measurements including any available boundary measurements. Estimated states from each area and its own boundary measurements will then be sent to the coordination center where the second stage estimation will be executed. The coordinate level state estimator will be responsible for the estimation of the coordination vector $x_S = \left[x^{b^T}, u^T\right]^T$ and also identifying and eliminating any bad data in the boundary measurements. It will also receive a limited set of synchronized phasor measurements, which are expected to significantly enhance the reliability and accuracy of the estimated states.

3.3.2 Individual Area State Estimation

In this study, the commonly used Weighted Least Squares (WLS) estimation method, which is introduced in last part, is adopted for all estimators. Hence, the individual area state estimation problem for each area is formulated as follows:

$$Minimize\ J_i = r_i^T R_i^{-1} r_i \tag{3.1}$$

$$Subject\ to\ z_i = h_i(x_i) + r_i \tag{3.2}$$

where,

z_i is the vector of available measurements in area i, having m_i elements. They include not only all the internal measurements but also the injection and flow measurements incident at the boundary buses and the area tie-lines.

r_i is the residual of measurement z_i.

R_i is the measurement error covariance matrix for area i.

$h_i(x_i)$ is the measurement function for area i measurements.

Through Chi-square test and largest normalized test, which are introduced in last part, the bad data can be detected and identified

It is assumed that it is the responsibility of individual areas to make sure that there is enough redundancy in the area measurement set to allow bad data identification and elimination for all internal area measurements. This means that at the completion of the individual area state estimations, the internal state estimate for area each area $\hat{x}^{\text{int}}$ can be assumed to be unbiased. If this is not the case, a proper meter placement program can be employed to upgrade the measurement system for the deficient area. A special scenario is shown in figure 5. to demonstrate the need of this assumption. In this scenario, the IEEE 14-bus system is decomposed into two areas. For the local level estimator for area I, the flow measurement 13-14 will be a critical measurement whose bad data is undetectable because of the decomposition of the system. However, in the integrated system, this measurement is no longer a critical measurement allowing its detection if it carries bad data.

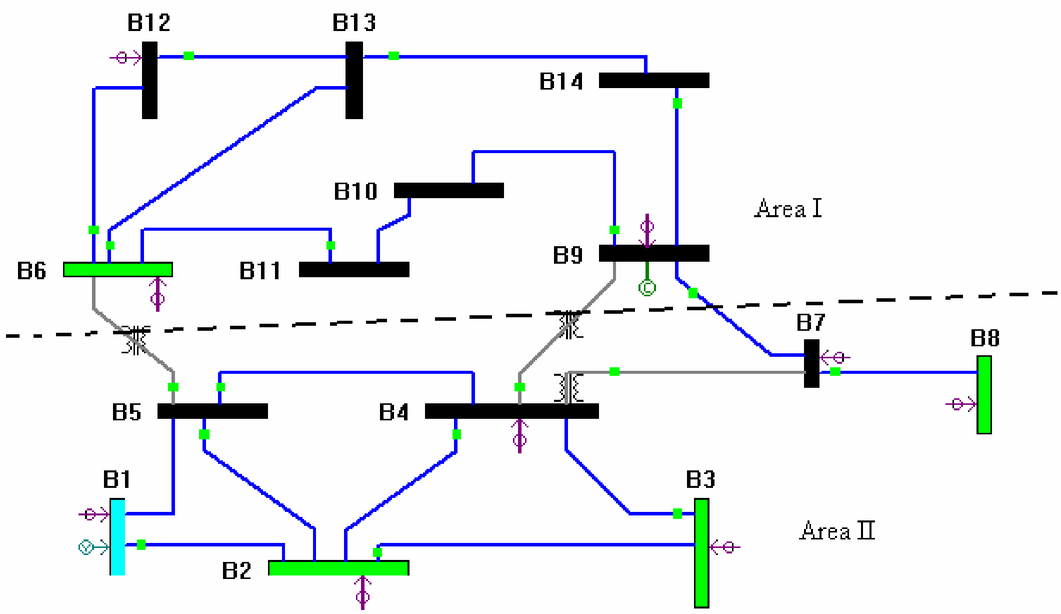

Figure 5 The Bad Data Cannot Be Identified in the Local Area SE Because of the Particular System Decomposition

The individual area SE makes use of any available boundary injections and tie-line flows. Hence, the estimated state vector is augmented by the external states associated with the neighboring boundary buses. On the other hand, if there are not sufficient or no such measurements incident at the boundary buses, then the associated states will simply be unobservable and therefore will be ignored.

3.3.3 System-wide State Estimation

The central coordinator will process the SE solutions from all areas along with the GPS based phasor measurements and raw measurements from area boundary buses in order to reach an unbiased estimate for the entire system state. This requires the solution of the following optimization problem:

$$\begin{aligned} \textit{Minimize } J_S &= r_S{}^T R_S{}^{-1} r_S \\ &= [z_S - h_S(x_S)]^T R_S{}^{-1}[z_S - h_S(x_S)] \end{aligned} \tag{3.3}$$

$$\textit{Subject to } z_S = h_S(x_S) + r_S \tag{3.4}$$

where

$z_S = \left[z_u{}^T, z_{ps}{}^T, \hat{x}^{b^T}, \hat{x}^{ext^T} \right]^T$, which represents all the available data and measurements to the coordinator.

z_u : Boundary measurement vector, which includes the tie-line flows and injections incident at all boundary buses.

z_{ps}: GPS synchronized phasor measurements vector.

r_S : the residual vector of measurement z_S.

$\hat{x}^b = \left[\hat{x}_1{}^{b^T}, \hat{x}_2{}^{b^T}, \cdots, \hat{x}_n{}^{b^T} \right]^T$: Boundary state variables estimated by individual area SEs. These are treated as pseudo-measurements by the coordinator SE. The covariance of these pseudo-measurements is obtained from the covariance matrix of the states $R_{x,i}$ for individual areas. This matrix is equal to the inverse of the gain matrix associated with that area's WLS state estimator.

$\hat{x}^{ext} = \left[\hat{x}_1{}^{ext^T}, \hat{x}_2{}^{ext^T}, \cdots, \hat{x}_n{}^{ext^T} \right]^T$, similar to $\hat{x}^b$, except defined for the external buses of each area.

The measurement model will then be given as:

$$z_S = h_S(x_S) + e_S \tag{3.5}$$

- $x_S{}^T = \left[x^{b^T}, u^T \right]$, is the coordination state vector whose dimension is n_S.

- e_S is the error vector of measurements, having a Normal distribution with zero mean and $R_S = E(e_S e_S{}^T)$ covariance.
- h_S is the non-linear function of x_i

It is noted that, each area will communicate its SE results for its boundary states $\hat{x}^b, \hat{x}^{ext}$ and its state covariance matrix $R_{x,i}$ to the coordinator. Furthermore, in general a boundary bus may have two pseudo measurements associated with its state, one provided by the solution of its own SE and another provided by the neighbor's SE. These will have different variances provided by different area SEs. In addition, since processing of the boundary injections will require the topology information around those boundary nodes that should also be provided to the central coordinator. This is the only "raw" information that needs to be provided to the coordinator, in addition to the results of the individual area state estimation. This scheme is quite suitable since it meets the security requirements for each area without having them release details of their internal system topology.

As expected, the effectiveness of the coordinator estimation strongly depends on the measurement redundancy and quality for this estimator. Synchronized phasor measurements can provide this redundancy very effectively. In both the individual area and the coordinator state estimation, the Largest Normalized Residual Test will be carried out to identify the bad data. Finally, it should be noted that due to the absence of iterations between the individual area and coordinator estimators, this two-part algorithm would in general not yield the same results as a single system-wide integrated estimator.

3.4 Simulation Results

A program is developed in order to simulate the proposed scheme and evaluate its performance. IEEE 118 bus test system and ERCOT's 4520 bus system are used for the simulations. The results are presented in three subsections. Part A and B include results obtained for the ERCOT and IEEE 118 bus systems respectively. Part C shows the impact of phasor measurements on the accuracy of the final estimates for both test systems.

Three cases are presented for both parts A and B. Case 1 is a comparison of integrated and proposed multi-area SE results for both systems. Case 2 illustrates the performance of the multi-area scheme when a single bad measurement exists on the boundary and becomes a critical measurement as a result of the decomposition. The last case demonstrates the benefits of having phasor measurements when there is low measurement redundancy around the area boundary buses in the system.

3.4.1 ERCOT 4520 Bus System

ERCOT system is partitioned into thirteen areas as shown in Figure 6. It is assumed that all areas have enough measurements to make the internal and boundary buses of each area observable.

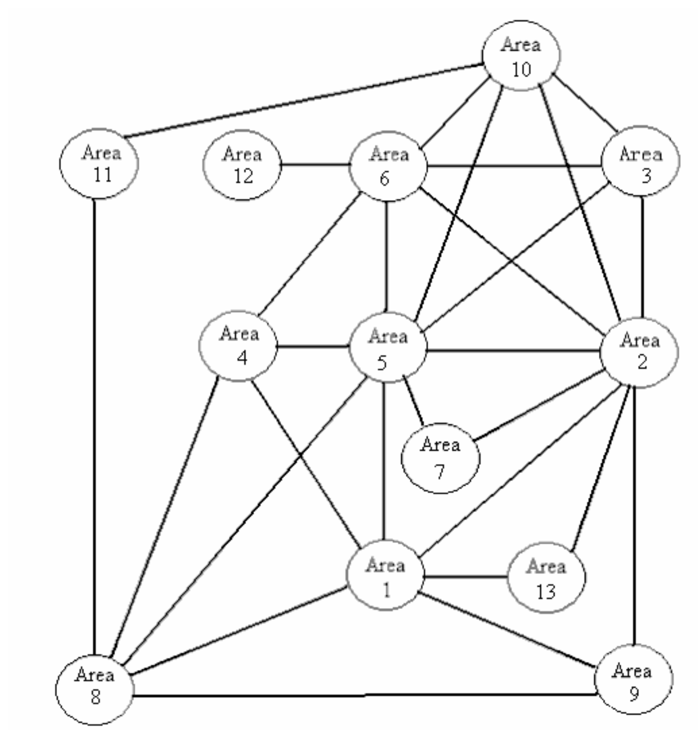

Figure 6 Control Areas of the ERCOT System

Case 1:

The measurements are chosen so that the integrated system as well as the individual areas is observable with no critical measurements. Flow measurements are placed at each branch and injections at all boundary buses. Some additional injections are placed where necessary in order to ensure that there are no critical measurements in the system. All the voltage, flow and injection measurements are added random errors with zero mean and following standard deviations ($\sigma_{voltage} = 0.004, \sigma_{injection} = 0.01, \sigma_{flow} = 0.008$).

Synchronized phasor measurements are assumed to have a standard deviation of $\sigma_{phasor} = 0.0001$. Altogether 13 phasor measurements are assumed to exist in the ERCOT system and their bus and area numbers are listed in Table 1.

Table 1. Phasor Measurements

Phasor Measurement	Bus Number	Area Number
1	1	8
2	800	9
3	1002	1
4	3831	4
5	3853	13
6	4001	2
7	5000	3
8	5500	10
9	5930	12
10	6006	4
11	7004	5
12	8033	6
13	9000	8

The simulated system has a total of 13 voltages, 5617 pairs of power flow, 1385 pairs of injection and 13 synchronized phasor measurements. Hence, total number of measurements and states are m=14030 and n=(4520*2-1)=9039 respectively. This yields a χ^2 test threshold of 5157 with 95% confidence level and a degree of freedom (d.f) of 14030-9039=4991. The objective function evaluated at the solution of state estimation for the integrated and multi-area solutions are shown in Table 2. Note that the discrepancy between the objective functions is expected since the multi-area estimator is sub-optimal due to the lack of iterations between the coordination and individual area solutions. However, since no bad data are simulated, the objective function values are well below the χ^2 test threshold.

Table 2. Results of Integrated and Multi-area SE Solutions in ERCOT System

System/ No. of areas	J(x): Objective Function	
	Integrated	Two-level
ERCOT / 13	765.3	782.9

<u>Case 2:</u>
Case 2 is repeated by introducing a single bad data to the injection at bus 3092 in area 1. The true injection is $P_{3092} = 0.0$ which is replaced by $P_{3092} = 2.0$. Figure 7 presents the magnified view of the interconnection between areas 1 and 13.

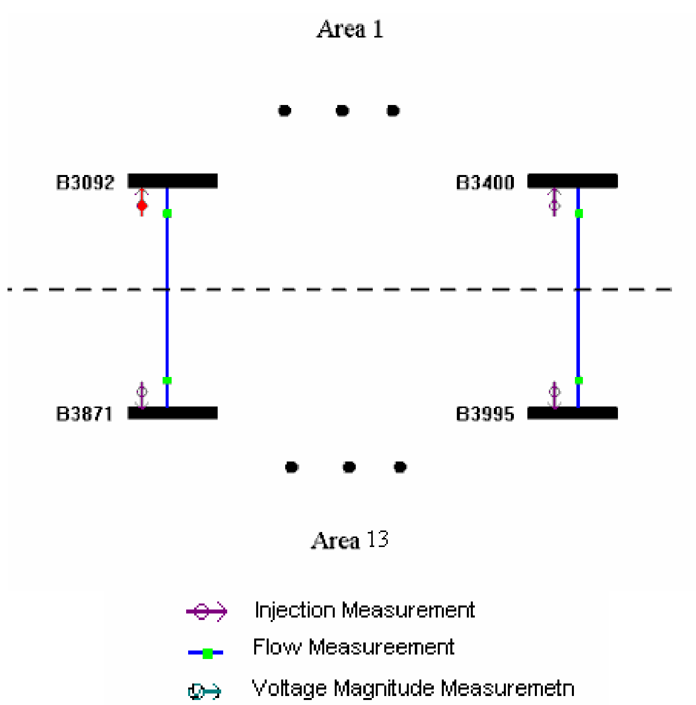

Figure 7 Magnified View of the Interconnection Between Areas 1 and 13.

Area 1 estimator yields an objective function, J(x) of 9538 which is above the χ^2 threshold of 1624 (at 95% confidence level and d.f. of 1532) and indicates the presence of bad data. Applying the largest normalized residual test, the injection at bus 3092 and flow through the line 3092-3871, which form a critical pair, are found to have the largest r_i^N =41.29.

In this case, even though bad data is detected, it cannot be identified by area 1 estimator. The central coordinator receives 504 pairs of injections, 1008 pairs of pseudo state measurements (estimated by all 13 area estimators), 550 pairs of flows, 1 voltage magnitude and 13 phasor measurements. Altogether, there are 504 boundary buses. The objective function evaluated by the coordinator is 16753, which is much larger than the Chi-squares threshold of 3240, again indicating bad data. Identification of bad data is carried out using the largest normalized residual test, which yields injection at bus 3092 having the largest r_i^N =42.78. After removing this bad data, J(x) drops down to 8736, which is still above the threshold. So, the pseudo angle measurement at bus 3871 which has the largest r_i^N =37.65 is identified as bad data. After removing this pseudo measurement no more bad data are detected.

Case 3:

In this case, the base case measurement configuration is modified by removing the injection and flow measurements between areas 1 and 13 as shown in Figure 8 as well as the injection and flow measurements between area 2 and 13. Hence area 13 is isolated from the rest of the system, except for the phasor measurements between the pairs of buses (1156,3960), (1198,3993) and a flow measurement on line (3092,3871). However, the flow measurement on line (3092-3871) is replaced by bad data, i.e. instead of the correct value of $P_{3092-3871} = 4.0$, a wrong value of $P_{3092-3871} = 6.0$ is substituted.

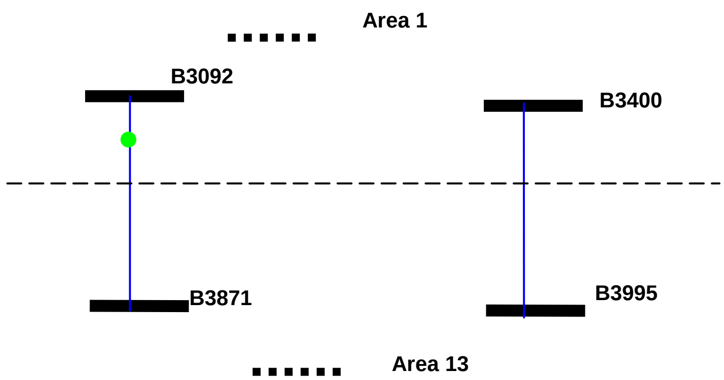

Figure 8 Boundary Measurements in Case 3.

The flow measurement on line (3092-3871) cannot be included in the individual area estimation. Furthermore, in the central coordination estimation, if there are no phasor measurements, the bad data on $P_{3092-3871}$ cannot be detected since it will be a critical measurement. Note that, in this case, there are no incident measurements on the boundary buses or tie-lines connecting area 1 to the rest of the system at buses 3871, and 3995. Hence, these buses are not included in the set of external buses for area 1.

In this case the central coordination estimation will yield a significant J(x) value of 17472 compared to the χ^2-test threshold for this system, which is 3219. Applying the largest normalized residual test correctly identifies the real power flow measurement on line (3092-3871) with r_i^N 43.67. After removing this bad data, no more bad data are detected. This case demonstrates the benefits of having synchronized phasor measurements when there is low measurement redundancy around the boundary buses of areas in the system. In this particular example, bad data on the tie-line power flow measurements would have gone undetected in the absence of phasor measurements processed by the central coordination estimator.

3.4.2 IEEE 118 Bus System

IEEE 118 bus system whose network data can be found in [51] is used for this study. This system is partitioned into nine areas as done in [52], and shown in Figure 9.

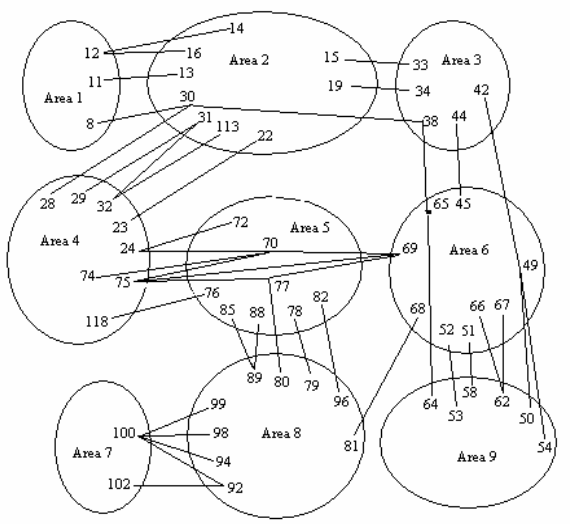

Figure 9 Control Areas of the IEEE 118 Bus System.

<u>*Case 1:*</u>

Apart from the conventional measurements, synchronized phasor measurements are assumed to exist between bus pairs (2,14), (4,13), (14,37), (24,37), (24,72), (47,72), (72,103), (81,103) and (55,81). A standard deviation of $\sigma_{phasor} = 0.0001$ is used to represent the noise in these measurements.

The system has a total of 9 voltage magnitudes, 187 pairs of power flow, 59 pairs of power injection and 9 synchronized phasor measurements. This yields a total number of

m=502 measurements, n=(2*118)-1=335 states, and a degree of freedom of 502-335=277. Hence, the Chi-squares test detection threshold is chosen as 317 corresponding to a 0.95 confidence level.

Similar to Case 1 of the ERCOT system, in this case the integrated and multi-area solutions are found to agree with each other very closely. Small discrepancy is again due to the sub-optimal nature of the proposed multi-area estimator. Table 3 shows the results obtained for both solutions for the 118 bus system.

Table 3 Results of Integrated and Multi-area SE Solutions n IEEE 118 System

System/ No. of areas	J(x)	
	Integrated	Two-level
IEEE / 9	15.43	15.65

Case 2:

In this case, a single bad data is introduced to the injection measurement at bus 11 by replacing the true value $P_{11} = -0.7$ by $P_{11} = -1.393$. Magnified view of the boundary measurements for area 1 are shown in Figure 10.

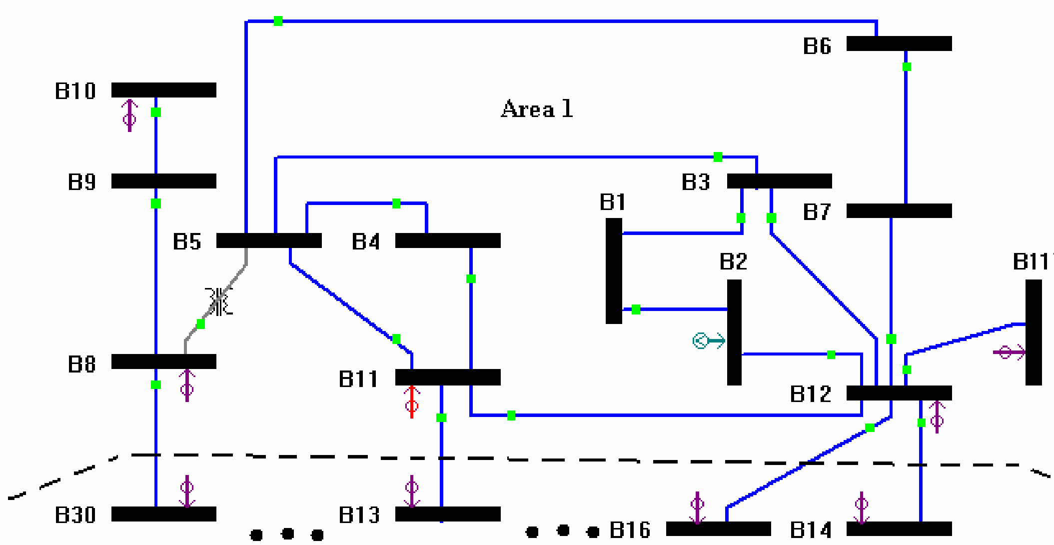

Figure 10 Area Topology and Measurements for Case 2

In this case, even though bad data is detected, it cannot be identified by area 1 estimator. This along with the incorrect pseudo angle measurement at bus 13 is successfully identified by the central coordinator estimation.

Case 3:

In this case, there is only one power flow measurement between area 1 and its neighbors and this real power measurement is simulated as bad data. There are however two phasor measurements between buses (2,14) and (4,13). In the absence of these phasor measurements, even the central coordinator cannot detect bad data on the critical flow measurement 11-13 in Figure 11. However, by introducing the phasor measurements, this bad data is detected and identified by the central coordinator estimation.

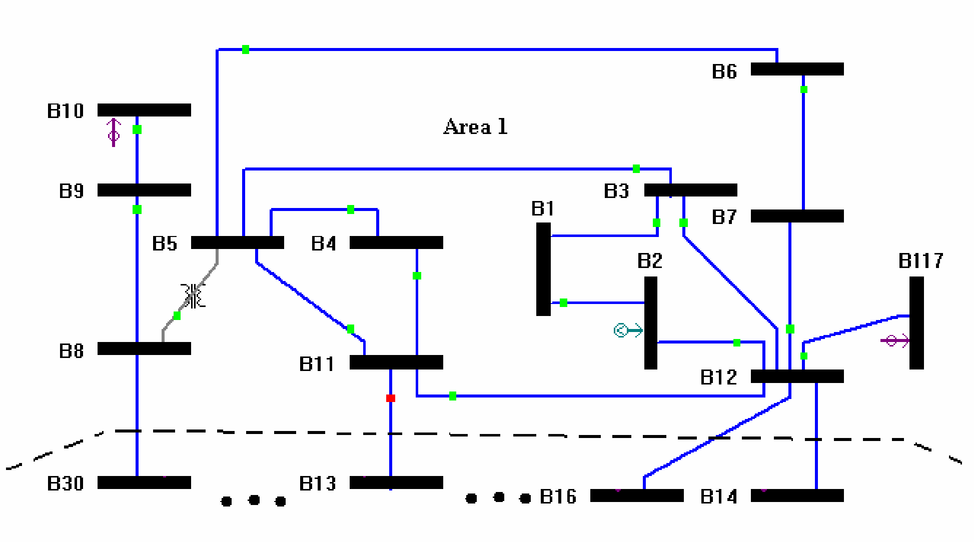

Figure 11 Topology and Measurement Locations for Case 3.

3.4.3 Effect of Phasor Measurement on SE Accuracy

In this section, the effect of including phasor measurements on the accuracy of the final state estimates is demonstrated. The results of state estimation with and without using phasor measurements are comparatively presented. The power flow result is used as the reference ("correct value") and the sum of squares and absolute values of the measurement residuals are used as the criteria in this comparison. Table 4 shows some simulation results corresponding to two test systems. The results indicate that the effect of phasor measurements on the accuracy of the estimated states and measurements is not significant when the measurements have only Gaussian noise. On the other hand, when there are gross errors in the boundary measurements, presence of phasor measurements makes an important difference as observed for Case 2 of parts A and B above.

Table 4. Effect of Using Phasor Measurements

System	Without Phasor Measurements		With Phasor Measurements	
	Sum of Squares of Residuals	Sum of Absolute Residuals	Sum of Squares of Residuals	Sum of Absolute Residuals
ERCOT	7.169e-4	2.473	6.817e-4	2.285
IEEE	1.873e-5	0.0645	1.588e-5	0.0585

3.5 Conclusions

This chapter investigates the state estimation problem in a multi-area framework. It is assumed that each area has its own state estimator, which processes the locally available measurements. Area state estimators may use different solution algorithms, data structures and post processing functions for bad data. Since they are required to only provide their state estimates to the central coordinator, they can operate independently without sharing network data with their neighbors or the coordinator. There is no information exchange between areas.

The proposed coordinator is a central entity, which has access to area state estimation solutions, raw measurements only from the area boundaries and few globally synchronized phasor measurements from area buses. This allows detection and identification of area boundary bus bad data, which will otherwise go undetected. Simulation results obtained for realistic size power systems with many areas are presented.

CHAPTER IV
TOTAL TRANSFER CAPABILITY

4.1 Problem Definition

In deregulated power systems, in order to have a reliable and economical electrical supply, it may need to transfer bulk electrical power over long distances. For example, the customers in Los Angeles may decide to buy the cheaper power from a power generator in Texas. But the power transmission network has a limitation to transfer the power. The maximum power that can be transferred through the transmission network under specified system conditions is called the transfer capability. To operate the power system safely and gain the maximum benefit of the transmission network, the transfer capability must be calculated. The system will be operated in the condition that the power transfer will not exceed the transfer capability.

Total Transfer Capability (TTC) is an important indicator of how much power can be exchanged between two buses in the power system without compromising the system security [53]-[55]. The accurate TTC provides important information for power system planners, operators and marketers. Planners need to know where the system bottlenecks are. Operators must not implement the transfers that may exceed the system transfer capability, and marketers need to know if the transaction can be executed or not. The accurate TTC calculation is needed to ensure that power system operate without causing the risk of system overloads, equipment damage or system collapse. However, too conservative estimate of TTC may limit the power transfer unnecessarily and will use the power network inefficiently.

The concept of Total Transfer Capability may be explained in terms of a simple 6-bus system, as shown in figure 12. In such a simple case, the additional power based on the specified system condition will be generated at bus 1 and transferred to bus 6. In this case bus 1 is called a source of power (sending bus) and bus 6 is called a sink of power (receiving bus). The TTC between bus 1 and 6 is the maximum power that can be delivered through the network without compromising the system security.

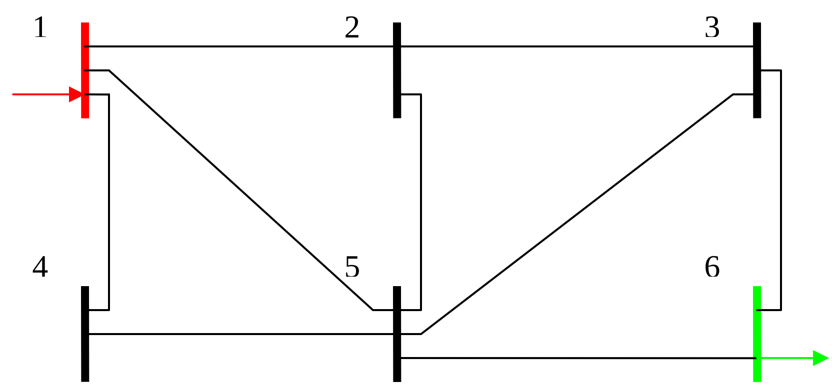

Figure. 12 Total Transfer Capability in a 6-bus System.

There are many assumptions and choices made in calculating the Total Transfer Capability, which may influence the results. These are system topology, transfer itself, the base case and limiting case, which will be described below.

- Base Case: the base case is a specified system operating condition to which the additional transfer is applied. The base case is assumed power system operating condition that is obtained by specifying power generation and consuming at each bus and the control settings then solving the power flows of overall system. It is also a secure operating condition that all quantities such as bus voltage and line flow are within their limits.
- Transfer: a transfer is described by the injection changes at two buses in a network. For example in figure 10, the power injection will be increased in bus 1 and reduced in bus 6. In particular case, if 10 MW are transferred from bus 1 to 6, the power injection at bus 6 is reduced by 10 MW and power injection at bus 1 increased by 10 MW plus the system losses changing.
- Limiting case: limiting case is such a operating condition that the transfer is increased to a value that system operating point meet a security limit. The system

security limit can be voltage magnitude, line flow or other operation constrains. If increase the transfer in limiting case, it will cause violations of system security limits, system will operate in insecurity condition. The security limits of an electrical transmission system may be anyone of the following:

1. Thermal Limits – The current flow in a conductor or electrical facility will cause heating. The thermal limit is the maximum amount of current that the transmission line or the facility can conduct without leading overheating or violating the other public safety requirement.
2. Voltage Limits – The adequate voltage must be maintained in the transmission network in normal condition, and even in a contingency. When electricity is transferred along a transmission line or transformer, the power loss (real and reactive power) occurs and a voltage drops. As the amount of transferred electricity is increasing, the power loss will increase, and the more reactive power is needed to support the system voltages, especially in the receiving area. When the reactive power generation is not enough, the voltages of the system will drops. The minimum voltage limits can be established to avoid the damage to system, customer facilities, or voltage collapse.
3. Stability Limits – When disturbances happen in the electrical system, the system should be capable of surviving, with safe maximum power transfer, through the disturbance time period. In transmission systems, all generators are connected and operated in synchronism with each other. When a system disturbance occurs, generators will oscillate from each other, and the system frequency, loading and bus voltages will fluctuate. If the disturbance is minor, the oscillation will damp out and the system will run in a new, stable operating point. If a new, stable operating point cannot be established, the generator will lose their synchronism with each other, the system will be unstable. The system will be uncontrollable and

the equipment may be damaged. The stability limits will be established to avoid the system unstable following the disturbance.

Now, we can summarize the TTC calculation and define the Transfer margin:

- Establish a base case, which is secure one;
- Define a transfer, which include a power source and sink;
- Establish a solved limiting case, in this case, one or more security limits will be encountered;
- Find out the maximum power, which can be delivered from source to sink through the transmission network.

The TTC calculation is based on some assumptions. When varying the base case, the TTC will be quite different from each other. Re-dispatch of the generation and load or different limits settings will have a particular effect on TTC. In this dissertation, there are some additional assumptions and approximations: the security limits which will be considered are line flow, voltage magnitude and voltage collapse, and for the transient limits, it will be crudely approximated into the flow limits; The transmission network is assumed to be fixed during the discussion, if there are any contingencies such as line outages, it will be incorporated into the network and be discussed as a new base case.

4.2 Formulation of the Problem

Consider a system with N buses. Hence we can address some definitions and terms for problem formulation.

Φ : Set of lines of the system;

σ : Set of PQ buses of the system.

In a power system, the TTC between a chosen sending bus I (Seller) and a receiving bus J (Buyer) can be addressed by solving the following optimization problem. Note that the sending bus I will automatically be selected as the slack bus and the load power (not injected power) at the Buyer bus is considered to be a positive power for TTC.

Objective Function:

$$Max\, P_J^{TTC} \tag{4.1}$$

Subject to

$$P_i = f_i(x, y) \quad i = 1 \cdots N, i \neq I, J \tag{4.2}$$

$$P_J - P_J^{TTC} = f_J(x, y) \tag{4.3}$$

$$Q_i = g_i(x, y) \quad i \in \sigma \tag{4.4}$$

$$\left|PF_i\right| \leq PF_i^{\max} \quad i \in \Phi \tag{4.5}$$

$$V_i^{\min} \leq V_i \leq V_i^{\max} \quad i = 1 \cdots N \tag{4.6}$$

Here,

P_J^{TTC}: TTC between sending bus I and receiving bus J;

Equality constrains (4.2-4.4) are power flow equations;

x: Power flow variable vector of the system, $x = \left[V_1, \cdots V_{N,} \theta_1, \cdots \theta_{I-1}, \theta_{I+1}, \cdots \theta_N\right]$

y: System topology parameter;

(4.5): The power flow limits for network branches;

(4.6): Voltage magnitude limits on the buses;

4.3 Existing Method of TTC Calculation

4.3.1 Continuation Methods

One way to calculate the TTC is via the use of continuation method [56]-[58]: from a solved base case, the power flow with an additional specified transfer will be sought. The amount of the transfer is a scalar parameter in the problem model. The continuation method obtains a series of power flow solutions by increasing the parameter, but avoiding sigularity of the Jacobian by way of a prediction-correction scheme.

4.3.2 Optimal Power Flow Approach

In the traditional regulated power system, the Optimal Power Flow (OPF) was an important tool in real-time or near real-time power system operation. However, in competitive environment of deregulated power system, there are some new challenges in OPF, such as new objectives, congestion control and increasing volatility of dispatch and operating conditions [59]-[62]. A lot of researchers have proposed to extend the OPF tools to the problems of ATC and TTC calculation, congestion control etc. Indeed, several papers [63]-[65] have been represented since 1999. Most of these papersshare a common theme: the problem is formulated as an optimization problem, with equality constrains which arise from the power flow, inequality constrains ranging from the basic operation and equipment limits to more detailed approximation of transient stability security requirements. Also for different problems, the objective functions vary widely. In some sense, OPF here is not the same as originally defined to find an economic solution for power generation and transmission and it has a single definition: an optimization problem using network power flow constrains.

4.3.3 Repeated Power Flow Method

Another way to calculate the TTC is by repeated power flow solutions [66],[67]. This approach starts from a base case, and repeatedly solves the power flow equations each time increasing the power transfer by a small increment until an operation limit is reached. The advantage of the repeated power flow approach is its simple implementation and the ease with which it can take voltage stability constraints into account. In this dissertation, we will use this method to solve the local area TTC problem.

4.4 Decentralized TTC Calculation

For TTC or ATC calculation, most papers focus on the integrated system solution, through applying continuation method or OPF approach, the problem can be solved directly. A recent paper [32] applies Bender’s decomposition to the available transfer capability calculations, and this method has a hierarchical structure. The objective is to maximize the power transfer between specified source and sink subject to the power flow equality constrains and system operation inequality limits. The “N-1” security criterion is used as the contingency available. The Bender decomposition breaks the original problem into two levels: In the first level (“Sub-problem”), each contingency is incorporated into a sub-problem, and they will be solved concurrently or gradually. Using an iterative algorithm, the integrated system solution can be solved in the second level (“Master problem”). This method has a hierarchical structure: for each contingency, it is a sub-problem, and the result from the sub-problems will be coordinated in the central entity.

The use of hierarchical structure in power system is not new. T.E. Dy-Liacco mentions a control center [22], which has hierarchical structure: each area has its own control center and a central entity coordinates the integrated system operation. Hierarchical concept is studied in the large-scale power system power flow, OPF and state estimation. The objective of previous works are mainly on the reduction in computing time, memory requirements and data exchange between areas in a large –scale power system.

A newly designed hierarchical state estimator which is suitable for multi-area power system is introduced in the last chapter. There are no information exchange between areas and limit information exchange between areas and central entity. Our objective is to apply this kind of design to TTC calculation in multi-area power system. The details will be introduced in the next chapter.

4.5 Summary

In this chapter, the definition of Total Transfer Capability is introduced as well as some other relative terms: base case, transfer, limiting case etc. TTC is defined as the maximum power can be delivered from a source to sink under a specified system operation condition without comprise the system security limits. Furthermore, the problem formulation and existing method of solving TTC problem is described. At last, a decentralized TTC calculation method is reviewed. All existing methods cannot satisfy the special requirement of multi-area power system TTC calculation. A newly designed method with a hierarchical structure, which is extended from the idea of state estimator introduced in the chapter III, will be described in the next chapter.

CHAPTER V

TOTAL TRANSFER CAPABILITY IN MULTI-AREA POWER SYSTEM

5.1 Introduction

The traditional methods in the present state, as defined in the last chapter, cannot solve the TTC problem in multi-area power system. In order to have a reliable and economical electrical supply in deregulated multi-area power system, however, it is necessary to transfer bulk electrical power over long distances and between different areas. The following pages will introduce a new method into the TTC calculation in multi-area power system.

Transmission open access enables power transactions to take place between remote locations, which may be separated by one or more control areas. It is therefore necessary to have a central entity to oversee the overall system operation so that the power transactions between different locations can be managed securely and without congestion. TTC is an important indicator of how much power can be exchanged between two points in the system. While the TTC calculation involves several considerations including the contingency analysis and checking stability limits, in this study only the line power flow and voltage limits will be considered.

TTC calculation for the overall system will be difficult in a power system with several areas, where there is limited or no information exchange (such as the network data, load and generation within the area) between the individual areas. One possible solution may be to let each area run its own TTC calculation and let a central entity coordinate these results from each area in a meaningful manner. The goal is to be able to compute a TTC value, which is very close to the TTC that would be calculated if the entire system information were available to a single central operator. Such hierarchical computational schemes have been proposed and applied to state estimation in the chapter III. Here, this kind of idea will be extended to the TTC calculation.

The main motivation of the chapter is to address the problem of heterogeneity among the databases and solution methods for the existing application functions maintained by different control areas. The fact that control areas are reluctant to share network and application data between them adds to this challenge. In the proposed method below, control areas are not required to share any data among themselves. However, they exchange some data and information with the central coordinating entity. Unlike some other functions such as protective relaying or generation control, TTC calculation can be carried out at a rate slower than real-time. This will allow the implementation of solution schemes, which may require communications between the coordinator and individual areas.

Before introducing the new scheme, some terms, which will be used in this chapter, will be defined here. Consider a system with N buses, which is composed of n inter-connected areas. It is assumed that each bus belongs to one and only one area, whereas a system branch may be inside an area or may be connecting two areas (Tie Line). Hence we can address some definitions and terms.

N_i : The number of buses in area i;

K : The number of total tie lines of integrated system;

K_i : The number of tie lines, which are connected to area i;

ψ_i : Set of PQ buses in area i;

λ_i : Set of boundary buses of area i, excluding the slack bus;

Ω_i : Set of internal buses of area i, excluding the slack bus;

Φ : Set of lines of integrated system;

Φ_i : Set of all lines internal to area i;

γ_j : Set of tie lines those are incident to boundary bus j;

σ : Set of PQ buses of integrated system.

T_k : Power flow on tie line k in Base Case;

ΔT_k : Incremental power in the power flow on tie line k;

The proposed approach makes use of the Power Transfer Distribution Factors (PTDF), which are commonly used in the analysis of power system markets [68]-[70]. It is defined as the sensitivity of the power flow through branch k to the bus injection at bus m.

$$PTDF_{k,m} = \frac{\Delta P_{Flow,k}}{\Delta P_{injection,m}}$$

For the nonlinear system, PTDF depends on the topology and operating point of the power system. That is, PTDFs change when a line outage or controllable element adjustment (such as Tap change or shunt capacitor change) occurs. As well, when the system operating point shifts, PTDFs change too. In some cases, the power system will be approximated as a linear DC system, in such a case, the DC PTDF depend only on the topology of the system.

5.2 Layout of TTC Calculation in Multi-area Power System

Consider a system with N areas, each area having its own area control center. A central coordinator will have communication links with each area. This constitutes the two-layer structure shown in Figure 13. The central coordinator will compute and update the Power Transfer Distribution Factors (PTDF) for all lines in the system based on the current system topology and broadcast the values corresponding to area tie-lines to each area sharing the respective tie-lines. Each area will adjust the sign of the PTDFs for its own tie-lines so that they are defined with respect to the flows leaving the area towards the neighboring areas. Then each area will solve its own TTC problem, details of which will be described later. The central coordinator will coordinate the results from each area and then determine the final TTC value between the specified buyer and sellers.

An area may belong to one of the following three categories:

1. An area which contains the sending bus I;
2. An area which contains the receiving bus J;

3. An area which contains neither.

The formulation of the TTC problem to be solved by individual areas will differ depending on their category.

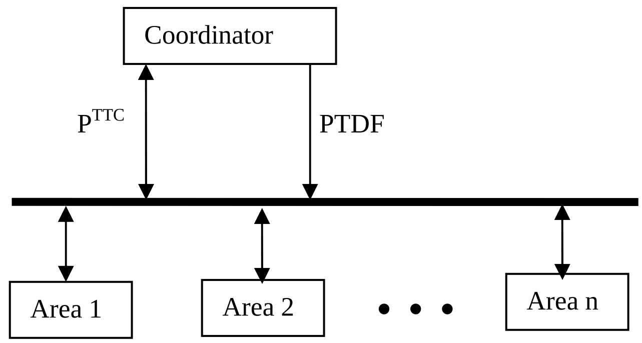

Figure 13 Two-layer Multi-area TTC Calculation Structure

In the next two sections, DC and AC TTC calculation in multi-area power system will be proposed separately. The problem formulation, proposed algorithm and numerical results will be detailed.

5.3 DC TTC Problem

5.3.1 Integrated System DC TTC Problem Formulation

In a power system, the TTC between a chosen sending bus I (Seller) and a receiving bus J (Buyer) can be found by solving the following optimization problem. Note that the sending bus I is considered the slack bus in the formulation.

$$Maximize \;\; P_J^{TTC} \tag{5.1}$$

Subject to

$$P_i = f_i(x, y) \qquad i = 1 \cdots N, i \neq I, J \tag{5.2}$$

$$P_J - P_J^{TTC} = f_J(x, y) \tag{5.3}$$

$$\left|PF_i\right| \leq PF_i^{\max} \quad i \in \Phi \tag{5.4}$$

Here,

P_J^{TTC} : TTC between the chosen sending bus and the receiving bus J;

Equations (5.2)-(5.3) are the DC power flow equations;

x : Phase angle vector, $x = [\theta_1, \cdots \theta_{I-1}, \theta_{I+1}, \cdots \theta_N]$

y : Network parameter;

Inequality constraints given by (5.4) represent the power flow limits for network branches.

5.3.2 Hierarchical TTC Problem Formulation

As introduced in the last section, for multi-are power system, each area will solve its own TTC problem. The central coordinator will compute and update the Power Transfer Distribution Factors (PTDF) for all lines in the system based on the current system topology and broadcast the values corresponding to area tie-lines to each area sharing the respective tie-lines. Then, the central coordinator will coordinate the results from each area and then determine the final TTC value between the specified buyer and sellers. An area may belong to one of three categories, and the formulations of the problem are different, which depend on their category.

If area i belongs to the first category, which contains the sending bus (bus I), then the sending bus will be automatically selected as the slack bus of the area and the problem can be formulated as:

$Maximize \quad P^{TTC}$

Subject to:

$$P_l = f_l(x, y) \qquad l \in \Omega_i \tag{5.5}$$

$$P_j - P_j^{TTC} = f_j(x, y) \quad j \in \lambda_i \tag{5.6}$$

$$P_j^{TTC} = -\sum_k \Delta T_k \quad k \in \gamma_j \tag{5.7}$$

$$\Delta T_k = -PTDF_k * P^{TTC} \quad k = 1 \cdots K_i \tag{5.8}$$

$$|PF_l| \leq PF_l^{\max} \quad l \in \Phi_i \tag{5.9}$$

$$\left|T_k + \Delta T_k\right| \le T_k^{\max} \quad k \in K_i \tag{5.10}$$

Here,

P^{TTC} : Area i’s TTC, which is to be determined.

$PTDF_k$: Power Transfer Distribution Factor between the tie line k and receiving bus J (in another area). Note that:

$\sum_{k-1}^{K_i} PTDF_k = 1$, so $P^{TTC} = -\sum_{k=1}^{Ki} \Delta T_k$;

Equations (5.5)-(5.6) are DC power flow equations;

x : Phase angle vector of the area;

y : Network parameter;

Inequality constraints (5.9) and (5.10) represent the branch power flow limits for the internal lines and tie lines of area i respectively.

If area i belongs to the second category, which contains the receiving bus (bus J), then an internal bus SL will be selected as the slack bus of the area and the problem can be formulated as:

$Maximize \quad P_J^{TTC}$

Subject to:

$$P_l = f_l(x, y) \qquad l \in \Omega_i, l \ne J \tag{5.11}$$

$$P_j - P_j^{TTC} = f_j(x, y) \;\; j \in \lambda_i, j \ne J \tag{5.12}$$

$$P_j^{TTC} = -\sum_k \Delta T_k \quad k \in \gamma_j \tag{5.13}$$

$$\Delta T_k = PTDF_k * P^{TTC} \quad k = 1 \cdots K_i \tag{5.14}$$

$$P_J - P_J^{TTC} = f_J(x, y) \tag{5.15}$$

$$\left|PF_l\right| \le PF_l^{\max} \quad l \in \Phi_i \tag{5.16}$$

$$\left|T_k + \Delta T_k\right| \le T_k^{\max} \quad k \in K_i \tag{5.17}$$

Here,

P_J^{TTC} : TTC to be determined;

$PTDF_k$: Power Transfer Distribution Factor between the tie line k and receiving bus J (in another area). Note that:

$\sum_{k-1}^{K_i} PTDF_k = -1$, so $P^{TTC} = \sum_{k=1}^{Ki} \Delta T_k$;

Equations (5.11), (5.12) and (5.15) are DC power flow equations;

x : Phase angle vector of area i;

y : Subsystem network parameter;

Equation (5.16) is the power flow limits of the branches in area i;

Equation (5.17) is the power flow limits of the tie lines of area i.

Equation (5.15) is the receiving bus DC power flow equation. It is assumed that bus J is not a boundary bus; otherwise below given equation will be used to replace equation (5.18):

$$P_J - P_J^{TTC} + \sum_k \Delta T_k = f_J(x, y) \quad k \in \gamma_J \tag{5.18}$$

If area i belongs to the third category, which does not contain either the sending or receiving buses, then an internal bus SL will be selected as the slack bus of the area. Assuming that the real power is injected into the area by tie lines $1 \cdots K_i^{In}$ and delivered to the neighboring areas by the rest of them $K_i^{In} + 1 \cdots K_i$ the problem can be formulated as:

$Maximize\, P^{TTC}$

Subject to:

$$P_l = f_l(x, y) \qquad l \in \Omega_i \tag{5.19}$$

$$P_j - P_j^{TTC} = f_j(x, y) \quad j \in \lambda_i \tag{5.20}$$

$$P_j^{TTC} = -\sum_k \Delta T_k \quad k \in \gamma_j \tag{5.21}$$

$$\Delta T_k = PTDF_k * P_{In}^{TTC} \quad k = 1 \cdots K_i^{In} \tag{5.22}$$

$$\Delta T_k = -PTDF_k * P^{TTC} \quad k = K_i^{In} + 1 \cdots K_i \tag{5.23}$$

$$\left|PF_l\right| \le PF_l^{\max} \quad l \in \Phi_i \tag{5.24}$$

$$\left|T_k + \Delta T_k\right| \le T_k^{\max} \quad k \in K_i \tag{5.25}$$

Here,

P^{TTC}, P_{In}^{TTC}: TTC to be optimized;

Equations (5.19) and (5.20) are power flow equations;

x: Phase angle vector of the area;

y: Network parameter;

$PTDF_k$: Power Transfer Distribution Factor between tie line k and receiving bus J (in another area). Note that:

$\sum_{k=1}^{K_i^{In}} PTDF_k + \sum_{k=K_i^{IN}+1}^{K_i} PTDF_k = 0$, since DC lossless model is assumed, $P^{TTC} = P_{In}^{TTC}$.

Equation (5.24) gives the power flow limits for the lines;

Equation (5.25) gives the power flow limits for the tie lines.

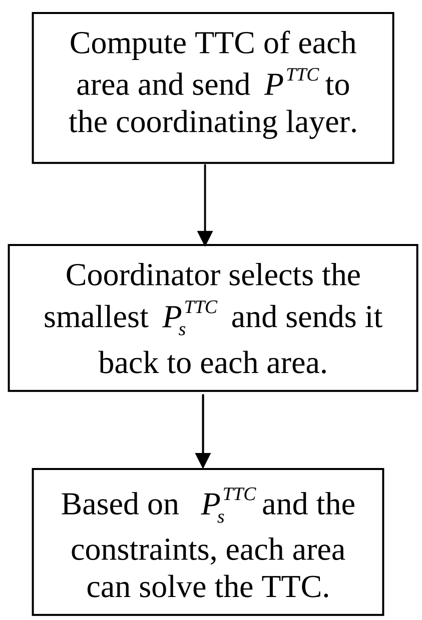

Figure 14 Flowchart for the Two-layer Algorithm

The central coordinator compares the values of P^{TTC} obtained from each area finds the smallest one and sends this smallest P^{TTC} back to all areas. The solution algorithm is summarized in the flowchart shown in Figure 14.

5.3.3 Solution Algorithm

The TTC problem formulation can be concisely described for all area categories as follows:

$$Maximize \quad J(P^{TTC}, \alpha, y) \tag{5.26}$$

Subject to:

$$F(P^{TTC}, \alpha, y) = 0 \tag{5.27}$$

$$G(P^{TTC}, \alpha, y) \le G^{Max} \tag{5.28}$$

P^{TTC} : TTC for the system;

α : Variable vector whose dimension is A, and includes all the variables except for P^{TTC} ;

y : Network parameter vector of each subsystem;

Equation (5.27) is the DC equality constraints vector whose dimension is B.

Note that, for the TTC problem A=B and the objective function will monotonously change with changing P^{TTC}. When P^{TTC} is fixed, the remaining variables can be solved through the linear equality constrains.

In order to solve the TTC problem described above, the incremental power flow method, whose flowchart is shown in Figure 15 will be applied. This will involve the following computational steps:

1) Increase the value of P^{TTC} ;
2) Solve the DC equality constraint equation (5.27);
3) Check if any limits are violated in (5.28);
4) If none are violated, go to step 1 and repeat steps 1-3; else record the value of P^{TTC} and send it to the coordinator layer.

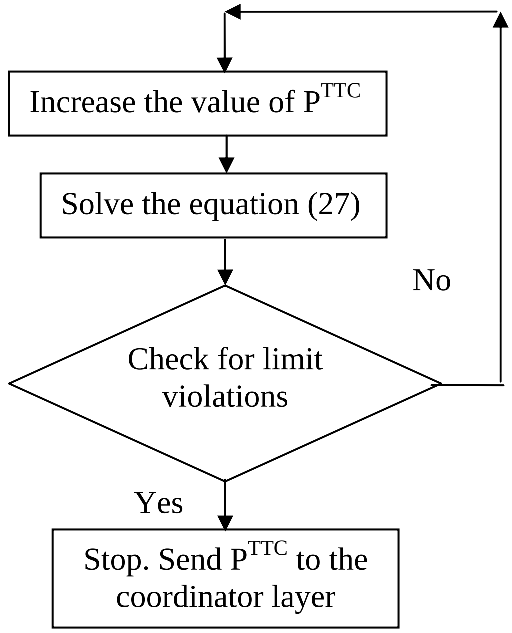

Figure 15. Computational Flowchart for Each Area

5.3.4 Numerical Simulation

The proposed two-layer multi-area solution scheme is implemented. IEEE 30 bus system is divided into three areas and is used for testing the implemented solution scheme. The system partitioning is shown in Figure 16.

The base case for the IEEE 30 bus system is used as the reference loading. A power transaction between the bus 1 (source) and bus 25 (sink) is considered. The objective is to find the TTC between bus 1 (sending bus) and bus 25 (receiving bus). Voltage limits are neglected and only the following MVA limits are considered to be active in the test system: $P_{6-28}^{\max} = 30MVA$, $P_{12-15}^{\max} = 25MVA$, $P_{6-9}^{\max} = 35MVA$. Applying the multi-area TTC algorithm, each area determines its TTC value as shown in Table 5. In area I, the limiting constraint is found to be the line flow limit on line 12-15, while for area II and III, the flow limit on the tie-line 6-28 is hit first, leading to the same TTC value for both areas. TTC results obtained by each area are shown in Table 5.

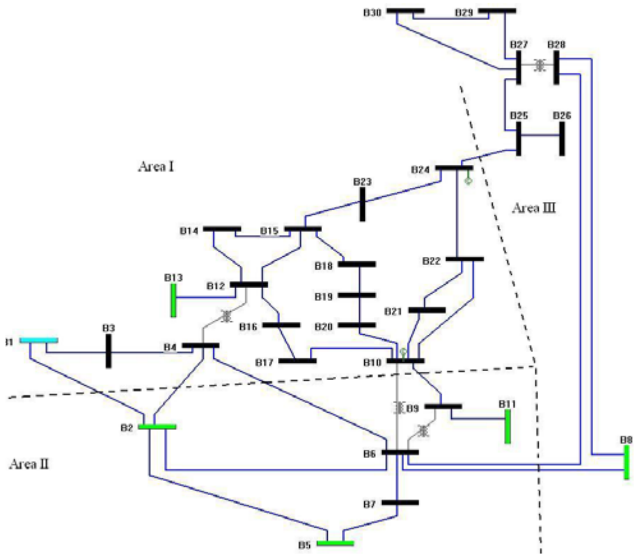

Figure 16 IEEE 30 bus System Partitioned into Three Areas

Table 5 P^{TTC} of Different Areas in DC Case

	Area I	Area II	Area III
P^{TTC} (MW)	57.20	25.38	25.38

Table 6 Results of the Integrated and Multi-area Calculations.

	Integrated system	Multi-area system
P^{TTC} (MW)	25.38	25.38

The coordinator selects the smallest P^{TTC} which is 25.38 and sets all area TTCs equal to $P^{TTC} = 25.38$. The comparison between the integrated versus the two-layer multi-area TTC calculations can be seen in Tables 6. Table 7 lists the phase angle solutions obtained by the two approaches.

As expected, the results of the integrated and multi-area two-layer methods are identical. This is not going to be true when the AC model is adopted and voltage constraints are considered in addition to the flows. Extension of this method to the coupled AC solution will be introduced in next section.

Table 7 Phase Angles Calculated by the Integrated and Multi-area Methods

Bus Number	Integrated system Result (Angle)	Multi-Area system Result (Angle)
1	0.0000	0.0000
2	-6.4515	-6.4515
3	-9.4207	-9.4207
4	-11.6170	-11.6170
5	-16.3830	-16.3830
6	-13.7193	-13.7193
7	-15.5004	-15.5004
8	-15.5567	-15.5567
9	-17.4272	-17.4272
10	-19.4322	-19.4322
11	-17.4272	-17.4272
12	-18.1227	-18.1227
13	-18.1227	-18.1227
14	-19.5809	-19.5809
15	-20.0585	-20.0585
16	-19.1994	-19.1994
17	-19.6981	-19.6981
18	-20.9164	-20.9164
19	-21.1302	-21.1302
20	-20.7806	-20.7806
21	-20.4796	-20.4796
22	-20.5228	-20.5228
23	-21.3203	-21.3203
24	-22.3853	-22.3853
25	-25.8173	-25.8173
26	-25.9208	-25.9208
27	-21.8963	-21.8963
28	-15.8308	-15.8308
29	-23.7450	-23.7450
30	-25.9650	-25.9650

The coordinator selects the smallest P^{TTC} which is 25.38 and sets all area TTCs equal to $P^{TTC} = 25.38$. The comparison between the integrated versus the two-layer multi-area TTC calculations can be seen in Tables 6. Table 7 lists the phase angle solutions obtained by the two approaches.

As expected, the results of the integrated and multi-area two-layer methods are identical. This is not going to be true when the AC model is adopted and voltage constraints are considered in addition to the flows. Extension of this method to the coupled AC solution will be introduced in next section.

5.4 AC TTC Problem

5.4.1 Integrated System AC TTC Problem Formulation

In an AC power system, the TTC between a chosen sending bus I (Seller) and a receiving bus J (Buyer) can be found by solving the following optimization problem. Note that the sending bus I will automatically be selected as the slack bus and the load power (not injected power) at the Buyer bus is considered to be a positive power for TTC.

Objective Function:

$$Max\, P_J^{TTC} \tag{5.29}$$

Subject to

$$P_i = f_i(x, y) \qquad i = 1 \cdots N, i \neq I, J \tag{5.30}$$

$$P_J - P_J^{TTC} = f_J(x, y) \tag{5.31}$$

$$Q_i = g_i(x, y) \qquad i \in \sigma \tag{5.32}$$

$$\left|PF_i\right| \leq PF_i^{\max} \quad i \in \Phi \tag{5.33}$$

$$V_i^{\min} \leq V_i \leq V_i^{\max} \quad i = 1 \cdots N \tag{5.34}$$

Here,

P_J^{TTC}: TTC between sending bus I and receiving bus J;

Equations (5.30)-(5.32) are power flow equation;

x : Power flow variable vector of the system, $x = \left[V_1, \cdots V_{N,} \theta_1, \cdots \theta_{I-1}, \theta_{I+1}, \cdots \theta_N\right]$

y : System topology parameter;

(5.33): The power flow limits for network branches;

(5.34): Voltage magnitude limits on the buses;

5.4.2 Hierarchical TTC Problem Formulation

The system is assumed to have N areas, each area having its own area control center. A central coordinator will have communication links with each area. The central coordinator will compute and update the DC Power Transfer Distribution Factors (PTDF) for all lines in the system based on the current system topology (base case) and provide them to each area. Each area will solve its own TTC problem details of which will be described later. The central coordinator will coordinate the results from each area and then determine the final TTC value between the specified buyer and sellers.

The formulation of the TTC problem will be different depending on the type of area. For each area, it is assumed that the tie line flow of Base Case T_k will be considered as one part of the load injection on boundary bus in the problem formulation.

For the area i, which contains sending bus (Bus I), it is assumed that the sending bus will be automatically looked as slack bus of the area and the problem can be formulated as:

Objective Function:

$Max \quad P^{TTC}$

Subjective to:

$$P_l = f_l(x, y) \qquad l \in \Omega_i \tag{5.35}$$

$$P_j - P_j^{TTC} = f_j(x, y) \;\; j \in \lambda_i \tag{5.36}$$

$$P_j^{TTC} = -\sum_k \Delta T_k \quad k \in \gamma_j \tag{5.37}$$

$$\Delta T_k = -PTDF_k * P^{TTC} \quad k = 1 \cdots K_i \tag{5.38}$$

$$Q_l = g_l(x, y) \quad l \in \psi_i \tag{5.39}$$

$$\left| PF_l \right| \le PF_l^{\max} \quad l \in \Phi_i \tag{5.40}$$

$$\left| T_k + \Delta T_k \right| \le T_k^{\max} \quad k \in K_i \tag{5.41}$$

$$V_j^{\min} \le V_j \le V_j^{\max} \quad i = 1 \cdots N_i \tag{5.42}$$

Here,

P^{TTC} : TTC to be determined;

Equations (5.35) (5.36) (5.39) are power flow equation;

x : Power flow variable vector of the area;

y : Network parameter vector;

$PTDF_k$: Power Transfer Distribution Factor between tie line k and receiving bus J (in another area);

(5.40): The power flow limits for network branches in this area;

(5.41): Power flow limits of tie lines;

(5.42): Voltage magnitude limits on the buses;

Hint: the "-"signal in equations (5.36)-(5.38) come from the different positive direction definition: TTC is defined as load, and ΔT_k is defined as flow injection.

For the area i, which contains receiving bus (Bus J), it is assumed that the bus SL is slack bus of the area and the problem can be formulated as:

Objective Function:

$Max\, P^{TTC}$

Subjective to:

$$P_l = f_l(x, y) \quad l \in \Omega_i, l \ne J \tag{5.43}$$

$$P_j - P_j^{TTC} = f_j(x, y) \;\; j \in \lambda_i, j \ne J \tag{5.44}$$

$$P_j^{TTC} = -\sum_k \Delta T_k \quad k \in \gamma_j \tag{5.45}$$

$$\Delta T_k = -PTDF_k * P_{In}^{TTC} \quad k = 1 \cdots K_i \tag{5.38}$$

$$P_J - P^{TTC} = f_J(x, y) \tag{5.46}$$

$$P_{SL}^{Base} = f_{SL}(x, y) \tag{5.47}$$

$$Q_l = g_l(x, y) \qquad l \in \psi_i \tag{5.48}$$

$$\left|PF_l\right| \le PF_l^{\max} \quad l \in \Phi_i \tag{5.49}$$

$$\left|T_k + \Delta T_k\right| \le T_k^{\max} \quad k \in K_i \tag{5.50}$$

$$V_j^{\min} \le V_j \le V_j^{\max} \quad i = 1 \cdots N_i \tag{5.51}$$

Here,

P^{TTC} : TTC to be determined;

Equations (5.43) (5.44) (5.46) (5.47) are power flow equation;

x : Power flow variable vector of the area;

y : Network parameter vector;

$PTDF_k$: Power Transfer Distribution Factor between tie line k and receiving bus J;

P_{SL}^{Base} : Injection on slack bus of Base Case;

(5.49): The power flow limits for network branches in this area;

(5.50): Power flow limits of tie lines;

(5.51): Voltage magnitude limits on the buses;

Equation (5.46) is receiving bus power flow equation. It is assumed that bus J is not a boundary bus, otherwise equation (5.52) will be used to replace equation (5.43);

$$P_J - P_J^{TTC} + \sum_k \Delta T_k = f_J(x, y) \quad k \in \gamma_J \tag{5.52}$$

For the area i, which does not contain sending bus (Bus I) or receiving bus (Bus J), it is assumed that the bus SL is slack bus of the area. The tie lines $1 \cdots K_i^{In}$ inject the real incremental power into the area and the tie line $K_i^{In} + 1 \cdots K_i$ deliver the real incremental power out to another area. The problem can be formulated as:

Objective Function:

$Max\, P^{TTC}$

Subjective to:

$$P_l = f_l(x,y) \quad l \in \Omega_i \tag{5.53}$$

$$P_j - P_j^{TTC} = f_j(x,y) \;\; j \in \lambda_i \tag{5.54}$$

$$P_j^{TTC} = -\sum_k \Delta T_k \quad k \in \gamma_j \tag{5.55}$$

$$\Delta T_k = -PTDF_k * P_{In}^{TTC} \quad k = 1 \cdots K_i^{In} \tag{5.56}$$

$$\Delta T_k = -PTDF_k * P^{ATC} \quad k = K_i^{In} + 1 \cdots K_i \tag{5.57}$$

$$P_{SL}^{Base} = f_{SL}(x,y) \tag{5.58}$$

$$Q_l = g_l(x,y) \quad l \in \psi_i \tag{5.59}$$

$$|PF_l| \le PF_l^{\max} \quad l \in \Phi_i \tag{5.60}$$

$$|T_k + \Delta T_k| \le T_k^{\max} \quad k \in K_i \tag{5.61}$$

$$V_j^{\min} \le V_j \le V_j^{\max} \quad i = 1 \cdots N_i \tag{5.62}$$

Here,

P^{TTC}, P_{In}^{TTC} : TTC to be determined;

Equations (5.53)(5.54)(5.55) are power flow equation;

x : Power flow variable vector of the area;

y : Network parameter vector;

$PTDF_k$: Power Transfer Distribution Factor between tie line k and receiving bus J;

P_{SL}^{Base} : Injection on slack bus of Base Case;

(5.60): The power flow limits for network branches in this area;

(5.61): Power flow limits of tie lines;

(5.62): Voltage magnitude limits on the buses;

5.4.3 Solution Algorithm

Sum all, for each area, the unified form of TTC problem for all areas will be address as:

Objective function:

$Max\ J(P^{TTC}, \alpha, y)$

Subject to:

$$F(P^{TTC}, \alpha, y) = 0 \tag{5.63}$$

$$G(P^{TTC}, \alpha, y) \le G^{Max} \tag{5.64}$$

P^{ATC} : Optimal variable;

α : Variable vector with the dimension A, include all the variables except P^{TTC};

y : Network parameter vector of each subsystem;

(5.63) is equation constrain with dimension B;

For the TTC problem, it is easy to find out that A=B and the objective function will monotonously change along with the P^{TTC} changing.

After the TTC of each area is solved, in coordinate level, compare the value of P^{TTC} from each area and select the smallest one; then send the smallest P^{TTC} back to all areas through solving equation (5.63), the solution of integrated system will be addressed. The flow char is as same as shown in Figure 5.2.

Remarks:

1) The DC PTDF is applied in this section. The advantage is that to generate the DC PTDF matrix, only topology information is enough, not like AC PTDF, it needs load and generation information, which may not be accessed because of the security reason; the disadvantage is that DC PTDF may not be as accurate as AC PTDF in AC TTC calculation.
2) Since PTDF cannot consider the reactive power flow, the voltage and reactive power in hierarchical case will be a little different from integrated system. When the power factor of the transmission lines is larger, then this kind of effect will be trivial.

As mentioned in last section, for the TTC problem, the objective function will monotonously change along with the P^{TTC} changing and when P^{TTC} is fixed, remain variables can be solved through the equation constrains. The continuous power flow method will be applied. The methods to solve the TTC problem depend on different area type.

For the area, which contains the sending bus:

1) Increasing the P^{TTC};
2) Solve the power flow;
3) Check if it exists any limits violation;
4) If no violation exists, go to step 1 and repeat step 1-3; other wise record the P^{TTC} and send to coordinate level;

For the area, which contains the receiving bus:

1) Increase the P^{TTC}, based on PTDF distribute the P^{TTC} to tie lines;
2) Solve the power flow;
3) Find out the generation change (ΔP) on slack bus;
4) Based on PTDF, distribute this ΔP to tie line;
5) Repeat step 2-4, until $\Delta P = 0$;
6) Check if it exists any limitation violations;
7) If no violation exists, go to step 1 and repeat 1-6; otherwise figure out the P^{TTC} and send to coordinate level;

For the area, which does not contain sending bus or receiving bus:

1) Identify all boundary buses into two sets;
   Power injection set (Set I): tie line inject the real incremental power to the area;
   Power deliver set (Set II): tie line deliver the real incremental power out of the area;
2) Increase the P^{TTC}, based on PTDF distribute the P^{TTC} to tie lines belong set II;

3) Solve the power flow;
4) Find out the generation change (ΔP) on slack bus;
5) Based on PTDF, distribute the ΔP to tie lines belong to set I;
6) Repeat 3-6 until $\Delta P = 0$;
7) Check if it exists limit violation;
8) If no violation exists, go to step 1 and repeat 1-6; otherwise send the P^{TTC};

5.4.4 Numerical Simulation

A program is developed in order to simulate the proposed scheme and evaluate its performance. IEEE 30 bus system with three areas and ERCOT 4520 bus system with 13 areas are used for this study.

5.4.4.1 IEEE 30 Bus Test System Result

The base case of this system is standard IEEE 30 bus data. The decomposition of the system is shown in Fig 5.5. The objective is to find the TTC between bus 1 (sending bus) and bus 25 (receiving bus). It is assumed that there is no voltage limitation, and MVA limitations are $P_{6-28}^{\max} = 30MVA$, $P_{12-15}^{\max} = 30MVA$, $P_{6-9}^{\max} = 35MVA$.

DC PTDF matrix is applied in the TTC calculation, after finishing the TTC of each area, the result is in Table 8:

Table 8 P^{TTC} of Different Area in AC Case

	Area I	Area II	Area III
P^{TTC} (MW)	58.66	27.88	28.32

The coordinate level select the smallest P^{TTC} as 27.88 and set all areas with the P^{TTC} as 27.88. Through solving the power flow with fixed P^{TTC} at each area; the overall system solution is addressed.

The comparison between integrated TTC and multi-area TTC is in Table 9

Table 9 TTC Results of Integrated System and Multi-area System

	Integrated system	Multi-area system
$\left\|P_1^{TTC}\right\|$ (MW)	33.13	33.60
$\left\|P_{25}^{TTC}\right\|$ (MW)	27.76	28.13

Here, P_1^{TTC} is the sending power at bus 1, and P_{25}^{TTC} is the receiving power at bus 25. The result on table shows that the Multi-area TTC calculation can find an accurate TTC value, which is very close to the integrated system TTC value.

5.4.4.2 ERCOT 4520 Bus System Result

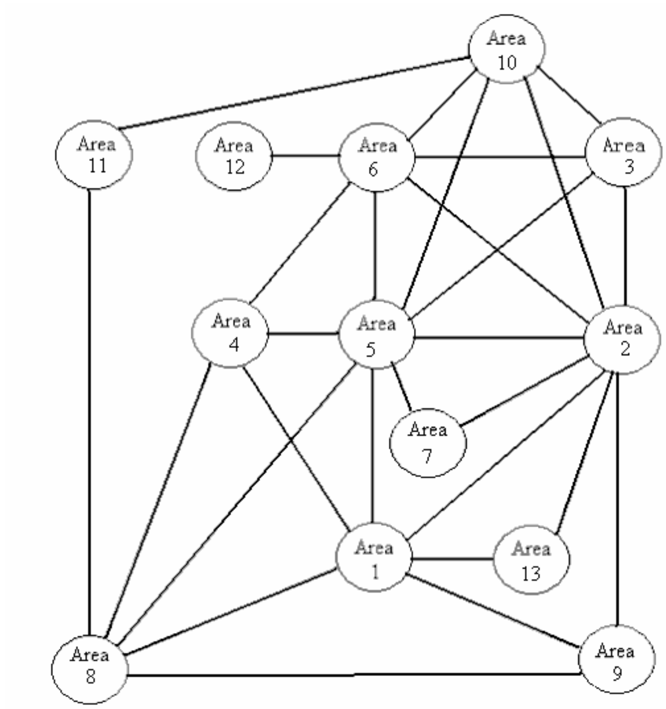

Figure17 ERCOT 4520 Bus System Partitioned into Thirteen Areas

The base case of this system is ERCOT 4520 bus system data. The decomposition of the system is shown in Figure 17. The objective is to find the TTC between 5026 (area 3) and 5905 (area 11). The decomposition of the ERCOT system is shown in Fig. 17

In this part, three limiting cases will be studied; each case will not have voltage limit violation but have one line flow limit violation at different area. DC PTDF as well as AC PTDF matrix will be applied in TTC calculation at each case separately. The result is listed in Table 10.

The result shows:

- The multi-area TTC result is very close to integrated TTC result.
- The more accurate PTDF the more accurate TTC result.

In order to generate the DC PTDF, the topology information of overall system is necessary; but for AC PTDF, not only the topology information but also the power flow information of current status (Jacobian matrix or load and injection information) of overall system are necessary. The advantage of applying AC PTDF is accurate result, but the price is more information exchange between area and central entity.

Table 10 TTC Results of Integrated System and Multi-area System of ERCOT 4520 Bus System

Line Limitation	Limitation value (MVA)	Integrated TTC (MW)	Multi-Area TTC with DC PTDF	Multi-Area TTC with AC PTDF
5901-5902 (area 11)	150	83.7	83.1	83.6
5025-5230 (area 3)	180	85.4	85.9	85.5
5502-5730 (area 10)	150	19.8	22.1	20.0

5.5 Conclusion

In this chapter a new method is presented, which has the hierarchical structure, to solve the TTC problem of Multi-area power system. The proposed set-up is particularly suitable for the deregulated power system with several areas where each area may solve its own TTC based on DC PTDF matrix, and the central entity coordinate the result from each area. There is no information exchange between each area, and limited information exchange between areas and central entity. Simulation results on 30 and 4520 bus system are shown to demonstrate the details of the proposed scheme.

CHAPTER VI

CONCLUSIONS

6.1 Summary

This dissertation addresses several important technical topics associated with the multi-area power system operation. After the deregulation of the power systems, operators are faced with the need to monitor and coordinate power transactions taking place over large distances in different areas of the power systems and each area has its own control center. The control areas are reluctant to share network and application data between them. But it is necessry to have central entity to monitor and control the overall system, so the overall system solutions (such as power flow, state estimation, total transfer capability calculation, etc.) are needed. A new application scheme, which has a hierarchical structure, is presented in the dissertation, and it is applied in the state estimation and total transfer capability calculation. Following are the main achievements of this dissertation:

- A new application scheme is designed to solve multi-area power system problem by giving local area centers freedom for solving their own problems while the central entity integrates their results. That is to say, in each area, the control center keeps its own applications, and the central entity addresses the overall system solution basing on the received results from each local area. As a result, the information exchange between the areas is avoided.
- In state estimation, through proper decomposition of the system, the boundary injection measurements can be used in the local area state estimator and coordinator state estimator.
- In state estimation, the issue of bad data detection at area boundaries is accomplished. The bad data can be detected and identified either by the local state estimator or by the coordinator state estimator.
- In state estimation, synchronized phasor measurements are applied in the coordinator state estimator. In case of low measurements redundancy at the area

boundaries, the phasor measurements can be helpful in improving the redundancy and detecting bad data by the coordinator state;

- In total transfer capability calculation, the power transfer distribution factors (PTDFs) are generated by the central entity and then are applied in the local TTC calculation so that no information is exchanged between the areas in solving local TTC problem.

6.2 Suggestions for Future Research

The work reported in this dissertation can be an important basis for future research activities related to multi-area system operation. In general, future research directions based on this dissertation are summarized below:

- In TTC calculation, the contingencies, such as line outage, may be considered in the future research.
- Extend the multi-area solution scheme evaluate the Available Transfer Capabiltiy (ATC) study, which involves other functions such as Capacity Benefit Margin (CBM), Transfer Reliability Margin (TRM).
- Another posibility is to extend the same idea to other application functions, such as voltage stability and transient stability calculations.

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APPENDIX A

DATA OF THE IEEE30-BUS SYSTEM

```
08/20/93 UW ARCHIVE           100.0  1961 W IEEE 30 Bus Test Case
BUS DATA FOLLOWS                             30 ITEMS
   1 Glen Lyn 132  1  1  3 1.060    0.0      0.0      0.0    260.2   -
16.1   132.0  1.060     0.0     0.0   0.0    0.0        0
   2 Claytor  132  1  1  2 1.043  -5.48     21.7     12.7     40.0
50.0   132.0  1.045    50.0   -40.0   0.0    0.0        0
   3 Kumis    132  1  1  0 1.021  -7.96      2.4      1.2      0.0
0.0   132.0  0.0       0.0     0.0   0.0    0.0        0
   4 Hancock  132  1  1  0 1.012  -9.62      7.6      1.6      0.0
0.0   132.0  0.0       0.0     0.0   0.0    0.0        0
   5 Fieldale 132  1  1  2 1.010 -14.37     94.2     19.0      0.0
37.0   132.0  1.010    40.0   -40.0   0.0    0.0        0
   6 Roanoke  132  1  1  0 1.010 -11.34      0.0      0.0      0.0
0.0   132.0  0.0       0.0     0.0   0.0    0.0        0
   7 Blaine   132  1  1  0 1.002 -13.12     22.8     10.9      0.0
0.0   132.0  0.0       0.0     0.0   0.0    0.0        0
   8 Reusens  132  1  1  2 1.010 -12.10     30.0     30.0      0.0
37.3   132.0  1.010    40.0   -10.0   0.0    0.0        0
   9 Roanoke  1.0  1  1  0 1.051 -14.38      0.0      0.0      0.0
0.0     1.0  0.0       0.0     0.0   0.0    0.0        0
  10 Roanoke   33  1  1  0 1.045 -15.97      5.8      2.0      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.19       0
  11 Roanoke   11  1  1  2 1.082 -14.39      0.0      0.0      0.0
16.2    11.0  1.082    24.0    -6.0   0.0    0.0        0
  12 Hancock   33  1  1  0 1.057 -15.24     11.2      7.5      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.0        0
  13 Hancock   11  1  1  2 1.071 -15.24      0.0      0.0      0.0
10.6    11.0  1.071    24.0    -6.0   0.0    0.0        0
  14 Bus 14    33  1  1  0 1.042 -16.13      6.2      1.6      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.0        0
  15 Bus 15    33  1  1  0 1.038 -16.22      8.2      2.5      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.0        0
  16 Bus 16    33  1  1  0 1.045 -15.83      3.5      1.8      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.0        0
  17 Bus 17    33  1  1  0 1.040 -16.14      9.0      5.8      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.0        0
  18 Bus 18    33  1  1  0 1.028 -16.82      3.2      0.9      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.0        0
  19 Bus 19    33  1  1  0 1.026 -17.00      9.5      3.4      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.0        0
  20 Bus 20    33  1  1  0 1.030 -16.80      2.2      0.7      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.0        0
  21 Bus 21    33  1  1  0 1.033 -16.42     17.5     11.2      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.0        0
  22 Bus 22    33  1  1  0 1.033 -16.41      0.0      0.0      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.0        0
```

```
  23 Bus 23    33  1  1  0 1.027 -16.61      3.2      1.6      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.0        0
  24 Bus 24    33  1  1  0 1.021 -16.78      8.7      6.7      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.043      0
  25 Bus 25    33  1  1  0 1.017 -16.35      0.0      0.0      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.0        0
  26 Bus 26    33  1  1  0 1.000 -16.77      3.5      2.3      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.0        0
  27 Cloverdle 33  1  1  0 1.023 -15.82      0.0      0.0      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.0        0
  28 Cloverdle132  1  1  0 1.007 -11.97      0.0      0.0      0.0
0.0   132.0  0.0       0.0     0.0   0.0    0.0        0
  29 Bus 29    33  1  1  0 1.003 -17.06      2.4      0.9      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.0        0
  30 Bus 30    33  1  1  0 0.992 -17.94     10.6      1.9      0.0
0.0    33.0  0.0       0.0     0.0   0.0    0.0        0
-999
BRANCH DATA FOLLOWS                         41 ITEMS
   1    2  1  1 1 0  0.0192    0.0575     0.0528     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
   1    3  1  1 1 0  0.0452    0.1652     0.0408     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
   2    4  1  1 1 0  0.0570    0.1737     0.0368     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
   3    4  1  1 1 0  0.0132    0.0379     0.0084     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
   2    5  1  1 1 0  0.0472    0.1983     0.0418     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
   2    6  1  1 1 0  0.0581    0.1763     0.0374     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
   4    6  1  1 1 0  0.0119    0.0414     0.0090     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
   5    7  1  1 1 0  0.0460    0.1160     0.0204     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
   6    7  1  1 1 0  0.0267    0.0820     0.0170     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
   6    8  1  1 1 0  0.0120    0.0420     0.0090     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
   6    9  1  1 1 0  0.0       0.2080     0.0        0     0     0
0 0  0.978     0.0 0.0    0.0     0.0    0.0   0.0
   6   10  1  1 1 0  0.0       0.5560     0.0        0     0     0
0 0  0.969     0.0 0.0    0.0     0.0    0.0   0.0
   9   11  1  1 1 0  0.0       0.2080     0.0        0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
   9   10  1  1 1 0  0.0       0.1100     0.0        0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
   4   12  1  1 1 0  0.0       0.2560     0.0        0     0     0
0 0  0.932     0.0 0.0    0.0     0.0    0.0   0.0
  12   13  1  1 1 0  0.0       0.1400     0.0        0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  12   14  1  1 1 0  0.1231    0.2559     0.0        0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  12   15  1  1 1 0  0.0662    0.1304     0.0        0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
```

```
  12   16  1  1 1 0  0.0945    0.1987      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  14   15  1  1 1 0  0.2210    0.1997      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  16   17  1  1 1 0  0.0524    0.1923      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  15   18  1  1 1 0  0.1073    0.2185      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  18   19  1  1 1 0  0.0639    0.1292      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  19   20  1  1 1 0  0.0340    0.0680      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  10   20  1  1 1 0  0.0936    0.2090      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  10   17  1  1 1 0  0.0324    0.0845      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  10   21  1  1 1 0  0.0348    0.0749      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  10   22  1  1 1 0  0.0727    0.1499      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  21   22  1  1 1 0  0.0116    0.0236      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  15   23  1  1 1 0  0.1000    0.2020      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  22   24  1  1 1 0  0.1150    0.1790      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  23   24  1  1 1 0  0.1320    0.2700      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  24   25  1  1 1 0  0.1885    0.3292      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  25   26  1  1 1 0  0.2544    0.3800      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  25   27  1  1 1 0  0.1093    0.2087      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  28   27  1  1 1 0  0.0       0.3960      0.0         0     0     0
0 0  0.968     0.0 0.0    0.0     0.0    0.0   0.0
  27   29  1  1 1 0  0.2198    0.4153      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  27   30  1  1 1 0  0.3202    0.6027      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
  29   30  1  1 1 0  0.2399    0.4533      0.0         0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
   8   28  1  1 1 0  0.0636    0.2000      0.0428      0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
   6   28  1  1 1 0  0.0169    0.0599      0.0130      0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0   0.0
-999
LOSS ZONES FOLLOWS                     1 ITEMS
  1 IEEE 30 BUS
-99
INTERCHANGE DATA FOLLOWS                 1 ITEMS
-9
 1    2 Claytor  132    0.0  999.99  IEEE30  IEEE 30 Bus Test Case
TIE LINES FOLLOWS                     0 ITEMS
```

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-999
END OF DATA
```

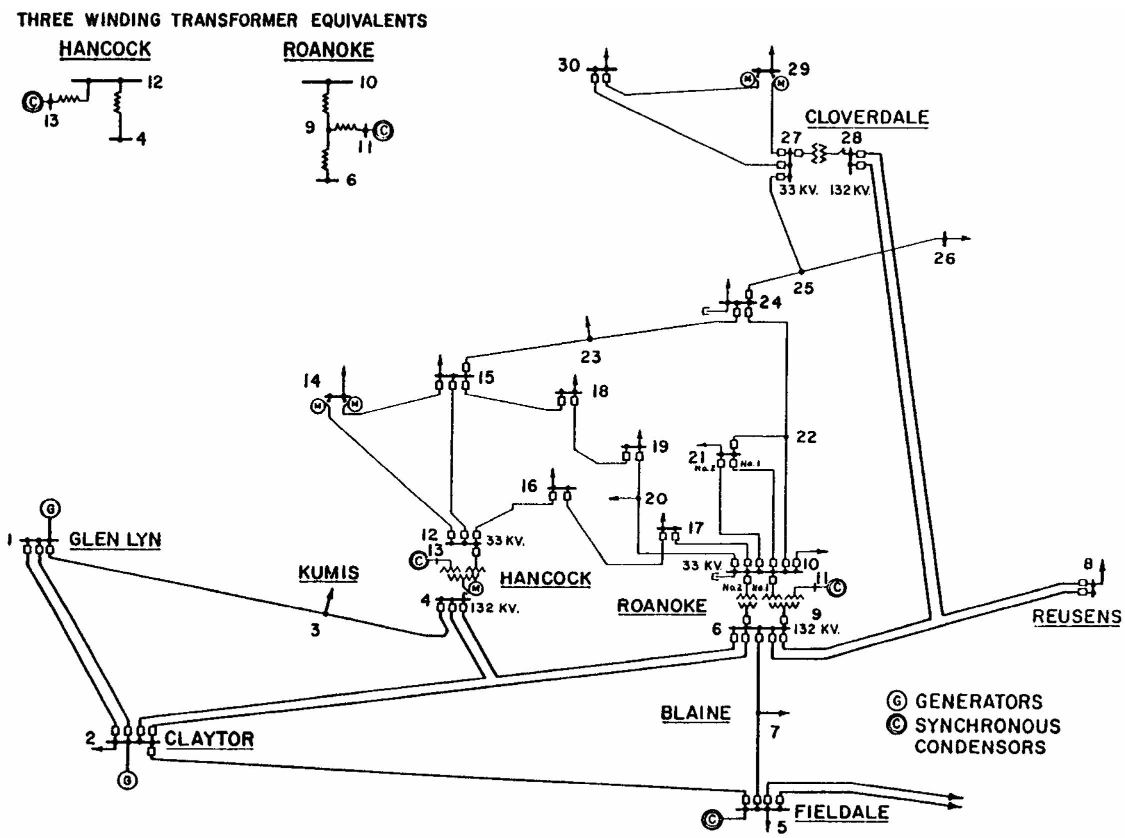

Figure. 18 IEEE 30 Bus System Diagram

APPENDIX B

DATA OF THE IEEE118-BUS SYSTEM

```
08/25/93 UW ARCHIVE          100.0  1961 W IEEE 118 Bus Test Case
BUS DATA FOLLOWS                             57 ITEMS
   1 Riversde  V2  1  1  2 0.955  10.67      51.0     27.0       0.0
0.0     0.0  0.955    15.0    -5.0   0.0    0.0       0
   2 Pokagon   V2  1  1  0 0.971  11.22      20.0      9.0       0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
   3 HickryCk  V2  1  1  0 0.968  11.56      39.0     10.0       0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
   4 NwCarlsl  V2  1  1  2 0.998  15.28      30.0     12.0      -9.0
0.0     0.0  0.998   300.0  -300.0   0.0    0.0       0
   5 Olive     V2  1  1  0 1.002  15.73       0.0      0.0       0.0
0.0     0.0  0.0       0.0     0.0   0.0   -0.40      0
   6 Kankakee  V2  1  1  2 0.990  13.00      52.0     22.0       0.0
0.0     0.0  0.990    50.0   -13.0   0.0    0.0       0
   7 JacksnRd  V2  1  1  0 0.989  12.56      19.0      2.0       0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
   8 Olive     V1  1  1  2 1.015  20.77       0.0      0.0     -28.0
0.0     0.0  1.015   300.0  -300.0   0.0    0.0       0
   9 Bequine   V1  1  1  0 1.043  28.02       0.0      0.0       0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  10 Breed     V1  1  1  2 1.050  35.61       0.0      0.0     450.0
0.0     0.0  1.050   200.0  -147.0   0.0    0.0       0
  11 SouthBnd  V2  1  1  0 0.985  12.72      70.0     23.0       0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  12 TwinBrch  V2  1  1  2 0.990  12.20      47.0     10.0      85.0
0.0     0.0  0.990   120.0   -35.0   0.0    0.0       0
  13 Concord   V2  1  1  0 0.968  11.35      34.0     16.0       0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  14 GoshenJt  V2  1  1  0 0.984  11.50      14.0      1.0       0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  15 FtWayne   V2  1  1  2 0.970  11.23      90.0     30.0       0.0
0.0     0.0  0.970    30.0   -10.0   0.0    0.0       0
  16 N. E.     V2  1  1  0 0.984  11.91      25.0     10.0       0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  17 Sorenson  V2  1  1  0 0.995  13.74      11.0      3.0       0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  18 McKinley  V2  1  1  2 0.973  11.53      60.0     34.0       0.0
0.0     0.0  0.973    50.0   -16.0   0.0    0.0       0
  19 Lincoln   V2  1  1  2 0.963  11.05      45.0     25.0       0.0
0.0     0.0  0.962    24.0    -8.0   0.0    0.0       0
  20 Adams     V2  1  1  0 0.958  11.93      18.0      3.0       0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  21 Jay       V2  1  1  0 0.959  13.52      14.0      8.0       0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  22 Randolph  V2  1  1  0 0.970  16.08      10.0      5.0       0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
```

```
  23 CollCrnr  V2  1  1  0 1.000  21.00      7.0       3.0       0.0
0.0     0.0  0.0       0.0      0.0   0.0    0.0        0
  24 Trenton   V2  1  1  2 0.992  20.89      0.0       0.0     -13.0
0.0     0.0  0.992   300.0  -300.0   0.0    0.0        0
  25 TannrsCk  V2  1  1  2 1.050  27.93      0.0       0.0     220.0
0.0     0.0  1.050   140.0   -47.0   0.0    0.0        0
  26 TannrsCk  V1  1  1  2 1.015  29.71      0.0       0.0     314.0
0.0     0.0  1.015  1000.0 -1000.0   0.0    0.0        0
  27 Madison   V2  1  1  2 0.968  15.35     62.0      13.0      -9.0
0.0     0.0  0.968   300.0  -300.0   0.0    0.0        0
  28 Mullin    V2  1  1  0 0.962  13.62     17.0       7.0       0.0
0.0     0.0  0.0       0.0      0.0   0.0    0.0        0
  29 Grant     V2  1  1  0 0.963  12.63     24.0       4.0       0.0
0.0     0.0  0.0       0.0      0.0   0.0    0.0        0
  30 Sorenson  V1  1  1  0 0.968  18.79      0.0       0.0       0.0
0.0     0.0  0.0       0.0      0.0   0.0    0.0        0
  31 DeerCrk   V2  1  1  2 0.967  12.75     43.0      27.0       7.0
0.0     0.0  0.967   300.0  -300.0   0.0    0.0        0
  32 Delaware  V2  1  1  2 0.964  14.80     59.0      23.0       0.0
0.0     0.0  0.963    42.0   -14.0   0.0    0.0        0
  33 Haviland  V2  1  1  0 0.972  10.63     23.0       9.0       0.0
0.0     0.0  0.0       0.0      0.0   0.0    0.0        0
  34 Rockhill  V2  1  1  2 0.986  11.30     59.0      26.0       0.0
0.0     0.0  0.984    24.0    -8.0   0.0    0.14       0
  35 WestLima  V2  1  1  0 0.981  10.87     33.0       9.0       0.0
0.0     0.0  0.0       0.0      0.0   0.0    0.0        0
  36 Sterling  V2  1  1  2 0.980  10.87     31.0      17.0       0.0
0.0     0.0  0.980    24.0    -8.0   0.0    0.0        0
  37 EastLima  V2  1  1  0 0.992  11.77      0.0       0.0       0.0
0.0     0.0  0.0       0.0      0.0   0.0   -0.25       0
  38 EastLima  V1  1  1  0 0.962  16.91      0.0       0.0       0.0
0.0     0.0  0.0       0.0      0.0   0.0    0.0        0
  39 NwLibrty  V2  1  1  0 0.970   8.41     27.0      11.0       0.0
0.0     0.0  0.0       0.0      0.0   0.0    0.0        0
  40 West End  V2  1  1  2 0.970   7.35     20.0      23.0     -46.0
0.0     0.0  0.970   300.0  -300.0   0.0    0.0        0
  41 S.Tiffin  V2  1  1  0 0.967   6.92     37.0      10.0       0.0
0.0     0.0  0.0       0.0      0.0   0.0    0.0        0
  42 Howard    V2  1  1  2 0.985   8.53     37.0      23.0     -59.0
0.0     0.0  0.985   300.0  -300.0   0.0    0.0        0
  43 S.Kenton  V2  1  1  0 0.978  11.28     18.0       7.0       0.0
0.0     0.0  0.0       0.0      0.0   0.0    0.0        0
  44 WMVernon  V2  1  1  0 0.985  13.82     16.0       8.0       0.0
0.0     0.0  0.0       0.0      0.0   0.0    0.10       0
  45 N.Newark  V2  1  1  0 0.987  15.67     53.0      22.0       0.0
0.0     0.0  0.0       0.0      0.0   0.0    0.10       0
  46 W.Lancst  V2  1  1  2 1.005  18.49     28.0      10.0      19.0
0.0     0.0  1.005   100.0  -100.0   0.0    0.10       0
  47 Crooksvl  V2  1  1  0 1.017  20.73     34.0       0.0       0.0
0.0     0.0  0.0       0.0      0.0   0.0    0.0        0
  48 Zanesvll  V2  1  1  0 1.021  19.93     20.0      11.0       0.0
0.0     0.0  0.0       0.0      0.0   0.0    0.15       0
  49 Philo     V2  1  1  2 1.025  20.94     87.0      30.0     204.0
0.0     0.0  1.025   210.0   -85.0   0.0    0.0        0
```

```
  50 WCambrdg  V2  1  1  0 1.001  18.90     17.0      4.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  51 Newcmrst  V2  1  1  0 0.967  16.28     17.0      8.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  52 SCoshoct  V2  1  1  0 0.957  15.32     18.0      5.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  53 Wooster   V2  1  1  0 0.946  14.35     23.0     11.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  54 Torrey    V2  1  1  2 0.955  15.26    113.0     32.0     48.0
0.0     0.0  0.955   300.0  -300.0   0.0    0.0       0
  55 Wagenhls  V2  1  1  2 0.952  14.97     63.0     22.0      0.0
0.0     0.0  0.952    23.0    -8.0   0.0    0.0       0
  56 Sunnysde  V2  1  1  2 0.954  15.16     84.0     18.0      0.0
0.0     0.0  0.954    15.0    -8.0   0.0    0.0       0
  57 WNwPhil1  V2  1  1  0 0.971  16.36     12.0      3.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  58 WNwPhil2  V2  1  1  0 0.959  15.51     12.0      3.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  59 Tidd      V2  1  1  2 0.985  19.37    277.0    113.0    155.0
0.0     0.0  0.985   180.0   -60.0   0.0    0.0       0
  60 SWKammer  V2  1  1  0 0.993  23.15     78.0      3.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  61 W.Kammer  V2  1  1  2 0.995  24.04      0.0      0.0    160.0
0.0     0.0  0.995   300.0  -100.0   0.0    0.0       0
  62 Natrium   V2  1  1  2 0.998  23.43     77.0     14.0      0.0
0.0     0.0  0.998    20.0   -20.0   0.0    0.0       0
  63 Tidd      V1  1  1  0 0.969  22.75      0.0      0.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  64 Kammer    V1  1  1  0 0.984  24.52      0.0      0.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  65 Muskngum  V1  1  1  2 1.005  27.65      0.0      0.0    391.0
0.0     0.0  1.005   200.0   -67.0   0.0    0.0       0
  66 Muskngum  V2  1  1  2 1.050  27.48     39.0     18.0    392.0
0.0     0.0  1.050   200.0   -67.0   0.0    0.0       0
  67 Summerfl  V2  1  1  0 1.020  24.84     28.0      7.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  68 Sporn     V1  1  1  0 1.003  27.55      0.0      0.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  69 Sporn     V2  1  1  3 1.035  30.00      0.0      0.0    516.4
0.0     0.0  1.035   300.0  -300.0   0.0    0.0       0
  70 Portsmth  V2  1  1  2 0.984  22.58     66.0     20.0      0.0
0.0     0.0  0.984    32.0   -10.0   0.0    0.0       0
  71 NPortsmt  V2  1  1  0 0.987  22.15      0.0      0.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  72 Hillsbro  V2  1  1  2 0.980  20.98      0.0      0.0    -12.0
0.0     0.0  0.980   100.0  -100.0   0.0    0.0       0
  73 Sargents  V2  1  1  2 0.991  21.94      0.0      0.0     -6.0
0.0     0.0  0.991   100.0  -100.0   0.0    0.0       0
  74 Bellefnt  V2  1  1  2 0.958  21.64     68.0     27.0      0.0
0.0     0.0  0.958     9.0    -6.0   0.0    0.12      0
  75 SthPoint  V2  1  1  0 0.967  22.91     47.0     11.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0       0
  76 Darrah    V2  1  1  2 0.943  21.77     68.0     36.0      0.0
0.0     0.0  0.943    23.0    -8.0   0.0    0.0       0
```

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  77 Turner    V2  1  1  2 1.006  26.72     61.0     28.0      0.0
0.0     0.0  1.006    70.0   -20.0   0.0    0.0        0
  78 Chemical  V2  1  1  0 1.003  26.42     71.0     26.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
  79 CapitlHl  V2  1  1  0 1.009  26.72     39.0     32.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.20       0
  80 CabinCrk  V2  1  1  2 1.040  28.96    130.0     26.0    477.0
0.0     0.0  1.040   280.0  -165.0   0.0    0.0        0
  81 Kanawha   V1  1  1  0 0.997  28.10      0.0      0.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
  82 Logan     V2  1  1  0 0.989  27.24     54.0     27.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.20       0
  83 Sprigg    V2  1  1  0 0.985  28.42     20.0     10.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.10       0
  84 BetsyLne  V2  1  1  0 0.980  30.95     11.0      7.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
  85 BeaverCk  V2  1  1  2 0.985  32.51     24.0     15.0      0.0
0.0     0.0  0.985    23.0    -8.0   0.0    0.0        0
  86 Hazard    V2  1  1  0 0.987  31.14     21.0     10.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
  87 Pinevlle  V3  1  1  2 1.015  31.40      0.0      0.0      4.0
0.0     0.0  1.015  1000.0  -100.0   0.0    0.0        0
  88 Fremont   V2  1  1  0 0.987  35.64     48.0     10.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
  89 ClinchRv  V2  1  1  2 1.005  39.69      0.0      0.0    607.0
0.0     0.0  1.005   300.0  -210.0   0.0    0.0        0
  90 Holston   V2  1  1  2 0.985  33.29     78.0     42.0    -85.0
0.0     0.0  0.985   300.0  -300.0   0.0    0.0        0
  91 HolstonT  V2  1  1  2 0.980  33.31      0.0      0.0    -10.0
0.0     0.0  0.980   100.0  -100.0   0.0    0.0        0
  92 Saltvlle  V2  1  1  2 0.993  33.80     65.0     10.0      0.0
0.0     0.0  0.990     9.0    -3.0   0.0    0.0        0
  93 Tazewell  V2  1  1  0 0.987  30.79     12.0      7.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
  94 Switchbk  V2  1  1  0 0.991  28.64     30.0     16.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
  95 Caldwell  V2  1  1  0 0.981  27.67     42.0     31.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
  96 Baileysv  V2  1  1  0 0.993  27.51     38.0     15.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
  97 Sundial   V2  1  1  0 1.011  27.88     15.0      9.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
  98 Bradley   V2  1  1  0 1.024  27.40     34.0      8.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
  99 Hinton    V2  1  1  2 1.010  27.04      0.0      0.0    -42.0
0.0     0.0  1.010   100.0  -100.0   0.0    0.0        0
 100 Glen Lyn  V2  1  1  2 1.017  28.03     37.0     18.0    252.0
0.0     0.0  1.017   155.0   -50.0   0.0    0.0        0
 101 Wythe     V2  1  1  0 0.993  29.61     22.0     15.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
 102 Smythe    V2  1  1  0 0.991  32.30      5.0      3.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
 103 Claytor   V2  1  1  2 1.001  24.44     23.0     16.0     40.0
0.0     0.0  1.01     40.0   -15.0   0.0    0.0        0
```

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 104 Hancock   V2  1  1  2 0.971  21.69     38.0     25.0      0.0
0.0     0.0  0.971    23.0    -8.0   0.0    0.0        0
 105 Roanoke   V2  1  1  2 0.965  20.57     31.0     26.0      0.0
0.0     0.0  0.965    23.0    -8.0   0.0    0.20       0
 106 Cloverdl  V2  1  1  0 0.962  20.32     43.0     16.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
 107 Reusens   V2  1  1  2 0.952  17.53     28.0     12.0    -22.0
0.0     0.0  0.952   200.0  -200.0   0.0    0.06       0
 108 Blaine    V2  1  1  0 0.967  19.38      2.0      1.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
 109 Franklin  V2  1  1  0 0.967  18.93      8.0      3.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
 110 Fieldale  V2  1  1  2 0.973  18.09     39.0     30.0      0.0
0.0     0.0  0.973    23.0    -8.0   0.0    0.06       0
 111 DanRiver  V2  1  1  2 0.980  19.74      0.0      0.0     36.0
0.0     0.0  0.980  1000.0  -100.0   0.0    0.0        0
 112 Danville  V2  1  1  2 0.975  14.99     25.0     13.0    -43.0
0.0     0.0  0.975  1000.0  -100.0   0.0    0.0        0
 113 Deer Crk  V2  1  1  2 0.993  13.74      0.0      0.0     -6.0
0.0     0.0  0.993   200.0  -100.0   0.0    0.0        0
 114 WMedford  V2  1  1  0 0.960  14.46      8.0      3.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
 115 Medford   V2  1  1  0 0.960  14.46     22.0      7.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
 116 KygerCrk  V2  1  1  2 1.005  27.12      0.0      0.0   -184.0
0.0     0.0  1.005  1000.0 -1000.0   0.0    0.0        0
 117 Corey     V2  1  1  0 0.974  10.67     20.0      8.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
 118 WHuntngd  V2  1  1  0 0.949  21.92     33.0     15.0      0.0
0.0     0.0  0.0       0.0     0.0   0.0    0.0        0
-999
BRANCH DATA FOLLOWS                         80 ITEMS
   1    2  1  1 1 0  0.03030   0.09990   0.02540     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
   1    3  1  1 1 0  0.01290   0.04240   0.01082     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
   4    5  1  1 1 0  0.00176   0.00798   0.00210     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
   3    5  1  1 1 0  0.02410   0.10800   0.02840     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
   5    6  1  1 1 0  0.01190   0.05400   0.01426     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
   6    7  1  1 1 0  0.00459   0.02080   0.00550     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
   8    9  1  1 1 0  0.00244   0.03050   1.16200     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
   8    5  1  1 1 1  0.00000   0.02670   0.0         0     0     0
0 0  0.985     0.0 0.0    0.0     0.0    0.0    0.0
   9   10  1  1 1 0  0.00258   0.03220   1.23000     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
   4   11  1  1 1 0  0.02090   0.06880   0.01748     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
   5   11  1  1 1 0  0.02030   0.06820   0.01738     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
```

```
  11   12  1  1 1 0  0.00595   0.01960   0.00502     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
   2   12  1  1 1 0  0.01870   0.06160   0.01572     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
   3   12  1  1 1 0  0.04840   0.16000   0.04060     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
   7   12  1  1 1 0  0.00862   0.03400   0.00874     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  11   13  1  1 1 0  0.02225   0.07310   0.01876     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  12   14  1  1 1 0  0.02150   0.07070   0.01816     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  13   15  1  1 1 0  0.07440   0.24440   0.06268     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  14   15  1  1 1 0  0.05950   0.19500   0.05020     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  12   16  1  1 1 0  0.02120   0.08340   0.02140     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  15   17  1  1 1 0  0.01320   0.04370   0.04440     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  16   17  1  1 1 0  0.04540   0.18010   0.04660     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  17   18  1  1 1 0  0.01230   0.05050   0.01298     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  18   19  1  1 1 0  0.01119   0.04930   0.01142     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  19   20  1  1 1 0  0.02520   0.11700   0.02980     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  15   19  1  1 1 0  0.01200   0.03940   0.01010     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  20   21  1  1 1 0  0.01830   0.08490   0.02160     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  21   22  1  1 1 0  0.02090   0.09700   0.02460     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  22   23  1  1 1 0  0.03420   0.15900   0.04040     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  23   24  1  1 1 0  0.01350   0.04920   0.04980     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  23   25  1  1 1 0  0.01560   0.08000   0.08640     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  26   25  1  1 1 1  0.00000   0.03820   0.0         0     0     0
0 0  0.960     0.0 0.0    0.0     0.0    0.0    0.0
  25   27  1  1 1 0  0.03180   0.16300   0.17640     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  27   28  1  1 1 0  0.01913   0.08550   0.02160     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  28   29  1  1 1 0  0.02370   0.09430   0.02380     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  30   17  1  1 1 1  0.00000   0.03880   0.0         0     0     0
0 0  0.960     0.0 0.0    0.0     0.0    0.0    0.0
   8   30  1  1 1 0  0.00431   0.05040   0.51400     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  26   30  1  1 1 0  0.00799   0.08600   0.90800     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
```

```
  17   31  1  1 1 0  0.04740   0.15630    0.03990     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  29   31  1  1 1 0  0.01080   0.03310    0.00830     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  23   32  1  1 1 0  0.03170   0.11530    0.11730     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  31   32  1  1 1 0  0.02980   0.09850    0.02510     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  27   32  1  1 1 0  0.02290   0.07550    0.01926     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  15   33  1  1 1 0  0.03800   0.12440    0.03194     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  19   34  1  1 1 0  0.07520   0.24700    0.06320     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  35   36  1  1 1 0  0.00224   0.01020    0.00268     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  35   37  1  1 1 0  0.01100   0.04970    0.01318     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  33   37  1  1 1 0  0.04150   0.14200    0.03660     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  34   36  1  1 1 0  0.00871   0.02680    0.00568     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  34   37  1  1 1 0  0.00256   0.00940    0.00984     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  38   37  1  1 1 1  0.00000   0.03750    0.0         0      0      0
0 0  0.935     0.0 0.0    0.0     0.0    0.0    0.0
  37   39  1  1 1 0  0.03210   0.10600    0.02700     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  37   40  1  1 1 0  0.05930   0.16800    0.04200     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  30   38  1  1 1 0  0.00464   0.05400    0.42200     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  39   40  1  1 1 0  0.01840   0.06050    0.01552     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  40   41  1  1 1 0  0.01450   0.04870    0.01222     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  40   42  1  1 1 0  0.05550   0.18300    0.04660     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  41   42  1  1 1 0  0.04100   0.13500    0.03440     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  43   44  1  1 1 0  0.06080   0.24540    0.06068     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  34   43  1  1 1 0  0.04130   0.16810    0.04226     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  44   45  1  1 1 0  0.02240   0.09010    0.02240     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  45   46  1  1 1 0  0.04000   0.13560    0.03320     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  46   47  1  1 1 0  0.03800   0.12700    0.03160     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  46   48  1  1 1 0  0.06010   0.18900    0.04720     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  47   49  1  1 1 0  0.01910   0.06250    0.01604     0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
```

```
  42   49  1  1 1 0  0.07150   0.32300   0.08600     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  42   49  1  1 1 0  0.07150   0.32300   0.08600     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  45   49  1  1 1 0  0.06840   0.18600   0.04440     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  48   49  1  1 1 0  0.01790   0.05050   0.01258     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  49   50  1  1 1 0  0.02670   0.07520   0.01874     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  49   51  1  1 1 0  0.04860   0.13700   0.03420     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  51   52  1  1 1 0  0.02030   0.05880   0.01396     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  52   53  1  1 1 0  0.04050   0.16350   0.04058     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  53   54  1  1 1 0  0.02630   0.12200   0.03100     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  49   54  1  1 1 0  0.07300   0.28900   0.07380     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  49   54  1  1 1 0  0.08690   0.29100   0.07300     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  54   55  1  1 1 0  0.01690   0.07070   0.02020     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  54   56  1  1 1 0  0.00275   0.00955   0.00732     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  55   56  1  1 1 0  0.00488   0.01510   0.00374     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  56   57  1  1 1 0  0.03430   0.09660   0.02420     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  50   57  1  1 1 0  0.04740   0.13400   0.03320     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  56   58  1  1 1 0  0.03430   0.09660   0.02420     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  51   58  1  1 1 0  0.02550   0.07190   0.01788     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  54   59  1  1 1 0  0.05030   0.22930   0.05980     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  56   59  1  1 1 0  0.08250   0.25100   0.05690     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  56   59  1  1 1 0  0.08030   0.23900   0.05360     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  55   59  1  1 1 0  0.04739   0.21580   0.05646     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  59   60  1  1 1 0  0.03170   0.14500   0.03760     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  59   61  1  1 1 0  0.03280   0.15000   0.03880     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  60   61  1  1 1 0  0.00264   0.01350   0.01456     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  60   62  1  1 1 0  0.01230   0.05610   0.01468     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  61   62  1  1 1 0  0.00824   0.03760   0.00980     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
```

```
  63   59  1  1 1 1  0.00000   0.03860    0.0          0      0      0
0 0  0.960     0.0 0.0    0.0     0.0    0.0    0.0
  63   64  1  1 1 0  0.00172   0.02000    0.21600      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  64   61  1  1 1 1  0.00000   0.02680    0.0          0      0      0
0 0  0.985     0.0 0.0    0.0     0.0    0.0    0.0
  38   65  1  1 1 0  0.00901   0.09860    1.04600      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  64   65  1  1 1 0  0.00269   0.03020    0.38000      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  49   66  1  1 1 0  0.01800   0.09190    0.02480      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  49   66  1  1 1 0  0.01800   0.09190    0.02480      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  62   66  1  1 1 0  0.04820   0.21800    0.05780      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  62   67  1  1 1 0  0.02580   0.11700    0.03100      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  65   66  1  1 1 1  0.00000   0.03700    0.0          0      0      0
0 0  0.935     0.0 0.0    0.0     0.0    0.0    0.0
  66   67  1  1 1 0  0.02240   0.10150    0.02682      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  65   68  1  1 1 0  0.00138   0.01600    0.63800      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  47   69  1  1 1 0  0.08440   0.27780    0.07092      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  49   69  1  1 1 0  0.09850   0.32400    0.08280      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  68   69  1  1 1 1  0.00000   0.03700    0.0          0      0      0
0 0  0.935     0.0 0.0    0.0     0.0    0.0    0.0
  69   70  1  1 1 0  0.03000   0.12700    0.12200      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  24   70  1  1 1 0  0.00221   0.41150    0.10198      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  70   71  1  1 1 0  0.00882   0.03550    0.00878      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  24   72  1  1 1 0  0.04880   0.19600    0.04880      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  71   72  1  1 1 0  0.04460   0.18000    0.04444      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  71   73  1  1 1 0  0.00866   0.04540    0.01178      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  70   74  1  1 1 0  0.04010   0.13230    0.03368      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  70   75  1  1 1 0  0.04280   0.14100    0.03600      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  69   75  1  1 1 0  0.04050   0.12200    0.12400      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  74   75  1  1 1 0  0.01230   0.04060    0.01034      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  76   77  1  1 1 0  0.04440   0.14800    0.03680      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  69   77  1  1 1 0  0.03090   0.10100    0.10380      0      0      0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
```

```
  75   77  1  1 1 0  0.06010   0.19990    0.04978     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  77   78  1  1 1 0  0.00376   0.01240    0.01264     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  78   79  1  1 1 0  0.00546   0.02440    0.00648     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  77   80  1  1 1 0  0.01700   0.04850    0.04720     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  77   80  1  1 1 0  0.02940   0.10500    0.02280     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  79   80  1  1 1 0  0.01560   0.07040    0.01870     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  68   81  1  1 1 0  0.00175   0.02020    0.80800     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  81   80  1  1 1 1  0.00000   0.03700    0.0         0     0     0
0 0  0.935      0.0 0.0    0.0     0.0    0.0    0.0
  77   82  1  1 1 0  0.02980   0.08530    0.08174     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  82   83  1  1 1 0  0.01120   0.03665    0.03796     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  83   84  1  1 1 0  0.06250   0.13200    0.02580     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  83   85  1  1 1 0  0.04300   0.14800    0.03480     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  84   85  1  1 1 0  0.03020   0.06410    0.01234     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  85   86  1  1 1 0  0.03500   0.12300    0.02760     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  86   87  1  1 1 0  0.02828   0.20740    0.04450     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  85   88  1  1 1 0  0.02000   0.10200    0.02760     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  85   89  1  1 1 0  0.02390   0.17300    0.04700     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  88   89  1  1 1 0  0.01390   0.07120    0.01934     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  89   90  1  1 1 0  0.05180   0.18800    0.05280     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  89   90  1  1 1 0  0.02380   0.09970    0.10600     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  90   91  1  1 1 0  0.02540   0.08360    0.02140     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  89   92  1  1 1 0  0.00990   0.05050    0.05480     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  89   92  1  1 1 0  0.03930   0.15810    0.04140     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  91   92  1  1 1 0  0.03870   0.12720    0.03268     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  92   93  1  1 1 0  0.02580   0.08480    0.02180     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  92   94  1  1 1 0  0.04810   0.15800    0.04060     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
  93   94  1  1 1 0  0.02230   0.07320    0.01876     0     0     0
0 0  0.0        0.0 0.0    0.0     0.0    0.0    0.0
```

```
  94   95  1  1 1 0  0.01320   0.04340    0.01110     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  80   96  1  1 1 0  0.03560   0.18200    0.04940     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  82   96  1  1 1 0  0.01620   0.05300    0.05440     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  94   96  1  1 1 0  0.02690   0.08690    0.02300     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  80   97  1  1 1 0  0.01830   0.09340    0.02540     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  80   98  1  1 1 0  0.02380   0.10800    0.02860     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  80   99  1  1 1 0  0.04540   0.20600    0.05460     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  92  100  1  1 1 0  0.06480   0.29500    0.04720     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  94  100  1  1 1 0  0.01780   0.05800    0.06040     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  95   96  1  1 1 0  0.01710   0.05470    0.01474     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  96   97  1  1 1 0  0.01730   0.08850    0.02400     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  98  100  1  1 1 0  0.03970   0.17900    0.04760     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  99  100  1  1 1 0  0.01800   0.08130    0.02160     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 100  101  1  1 1 0  0.02770   0.12620    0.03280     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  92  102  1  1 1 0  0.01230   0.05590    0.01464     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 101  102  1  1 1 0  0.02460   0.11200    0.02940     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 100  103  1  1 1 0  0.01600   0.05250    0.05360     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 100  104  1  1 1 0  0.04510   0.20400    0.05410     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 103  104  1  1 1 0  0.04660   0.15840    0.04070     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 103  105  1  1 1 0  0.05350   0.16250    0.04080     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 100  106  1  1 1 0  0.06050   0.22900    0.06200     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 104  105  1  1 1 0  0.00994   0.03780    0.00986     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 105  106  1  1 1 0  0.01400   0.05470    0.01434     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 105  107  1  1 1 0  0.05300   0.18300    0.04720     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 105  108  1  1 1 0  0.02610   0.07030    0.01844     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 106  107  1  1 1 0  0.05300   0.18300    0.04720     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 108  109  1  1 1 0  0.01050   0.02880    0.00760     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
```

```
 103  110  1  1 1 0  0.03906   0.18130    0.04610     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 109  110  1  1 1 0  0.02780   0.07620    0.02020     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 110  111  1  1 1 0  0.02200   0.07550    0.02000     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 110  112  1  1 1 0  0.02470   0.06400    0.06200     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  17  113  1  1 1 0  0.00913   0.03010    0.00768     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  32  113  1  1 1 0  0.06150   0.20300    0.05180     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  32  114  1  1 1 0  0.01350   0.06120    0.01628     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  27  115  1  1 1 0  0.01640   0.07410    0.01972     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
 114  115  1  1 1 0  0.00230   0.01040    0.00276     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  68  116  1  1 1 0  0.00034   0.00405    0.16400     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  12  117  1  1 1 0  0.03290   0.14000    0.03580     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  75  118  1  1 1 0  0.01450   0.04810    0.01198     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
  76  118  1  1 1 0  0.01640   0.05440    0.01356     0     0     0
0 0  0.0       0.0 0.0    0.0     0.0    0.0    0.0
-999
LOSS ZONES FOLLOWS                     1 ITEMS
  1 IEEE 118 BUS
-99
INTERCHANGE DATA FOLLOWS               1 ITEMS
 1   80 CabinCrk  V2    0.0  999.99  IEEE118 IEEE 118 Bus Test Case
-9
TIE LINES FOLLOWS                      0 ITEMS
-999
END OF DATA
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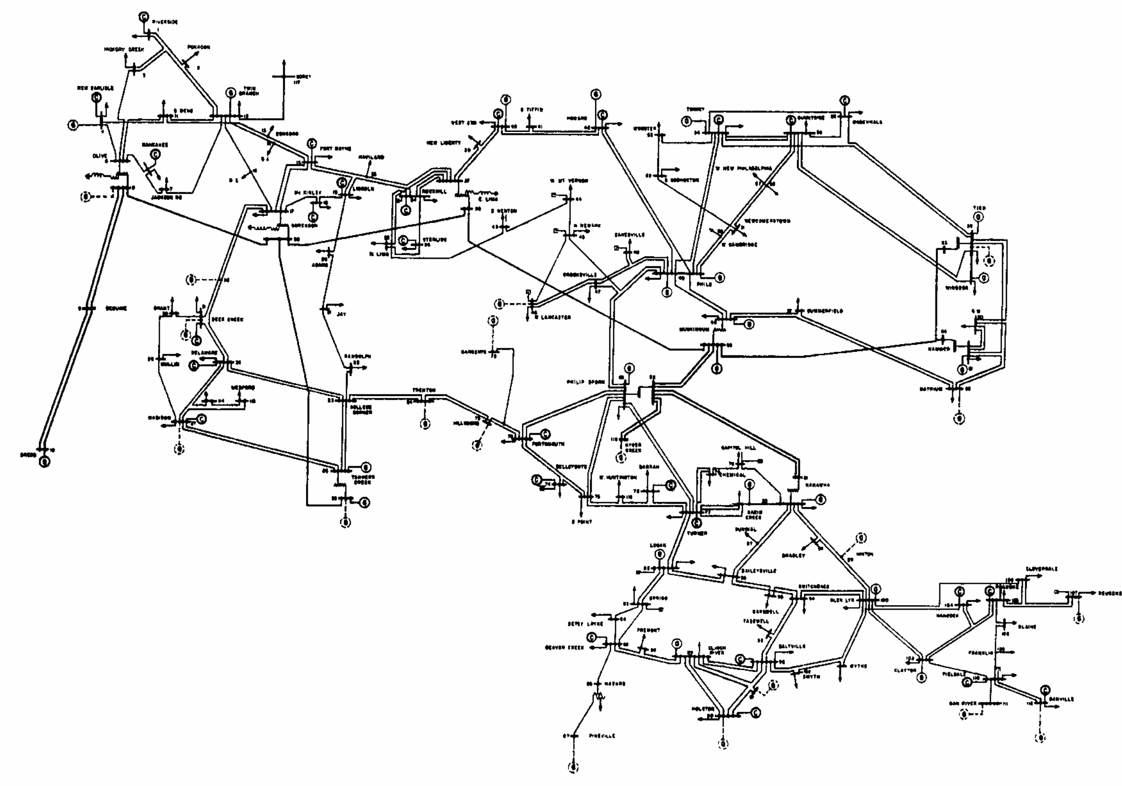

Figure. 19 IEEE 118 Bus System Diagram

VITA

Liang Zhao was born in Haimen, JiangSu province of P.R.China. He received his Bachelor of Science degree in electrical engineering from Tsinghua Unversity in July 1994. He continued his studies as a graduate student and research assistant at Tsinghua University during 1996-1998 and received the Master of Science degree in electrical engineering in July 1998. Since September 2000, he has been with Texas A&M University, working towards his Doctor of Philosophy degree in the Electrical Engineering Department. During his Ph.D. program, he worked as Graduate Research Assistant for the PSERC project, Graduate Assistant Non Teaching for the ELEN-460. His research interests include power market, power system operation and planning. He is a student member of the IEEE, the IEEE Power Engineering Society.

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