KEMA Consulting
KEMA-ECC & Macro Corporation

Analysis and Selection of Analytical Tools to Assess National-Interest Transmission Bottlenecks

Final Report

This work described in this report was coordinated by the Consortium for Electric Reliability Technology Solutions and funded by the U.S. Department of Energy, Office of Electric Transmission and Distribution under Contract No. DE-AC03-76SF00098.

March 2003

Executive Summary

KEMA Consulting has assessed existing commercial tools in the U.S. market that might be used to help support future DOE assessments of national interest transmission bottlenecks, consistent with recommendations in the DOE National Transmission Grid Study. The tool or tools must be capable of supporting studies of power systems transmission, energy, and ancillary services and markets as well as trading behavior. The working definition of *"national-interest transmission bottlenecks"* that has been used in this assignment is transmission bottlenecks that:

- Create congestion that significantly decrease reliability
- Restrict competition
- Enhance opportunities for suppliers to exploit market power
- Increase prices to consumers
- Increase infrastructure vulnerabilities
- Increase the risk of blackouts

The assessment of a bottleneck requires quantifying the reliability and economic impacts that they create, as well as those that would be avoided, if the bottleneck is removed or reduced. This assessment can be achieved by a set of tools that estimates the price of electricity in any specific location and assesses the impacts of physical constraints or bottlenecks on these prices. These prices can be used in assessing the cost of a bottleneck to the consumer as one aspect of the national economic impact of bottlenecks. In any study of bottlenecks and of options to relieve them both of these activities, i.e. reliability and economic assessments, must be conducted in order to evaluate the costs of bottlenecks and benefits of relieving them.

The main goal of this study is to identify a set of tools that in general can:

- Model the economic and power flow characteristics of the US electricity system
- Identify transmission bottlenecks (power flow constraints) within and among regions
- Identify assets or resources (e.g. transmission lines, generators) or other alternatives and upgrades that can eliminate these bottlenecks i.e., by eliminating or reducing the constraints.

The results of these assessments can be utilized to assess business and national impacts. The assessments by nature must be conducted for at least a 20-year planning horizon.

The general requirements for the assessment tool(s) include:

- Methodologies that enable the users to identify/verify specific transmission bottlenecks.
- Tools that forecast the price of electricity at specific locations or zones for specified periods of time. The price forecast must be developed for two cases: one of having the specific bottleneck, another of having the bottleneck relief in service.
- Ability to conduct the assessment studies for up to twenty future years in flexible intervals (hourly, daily, monthly, and annual).
- Ability to easily calibrate the models and subsystems of the tools.

The following set of tools were identified as requirements for conducting the bottleneck assessment studies (see Figure EX-1):

- Data modeling tools and packages
- Long term load forecast package
- Fuel price forecast data
- Electricity modeling system that consists of two separate subsystems:
    - Electricity Market Simulation
    - Real Time Dispatch and Optimal AC Power Flow
- Monte-Carlo simulation package.

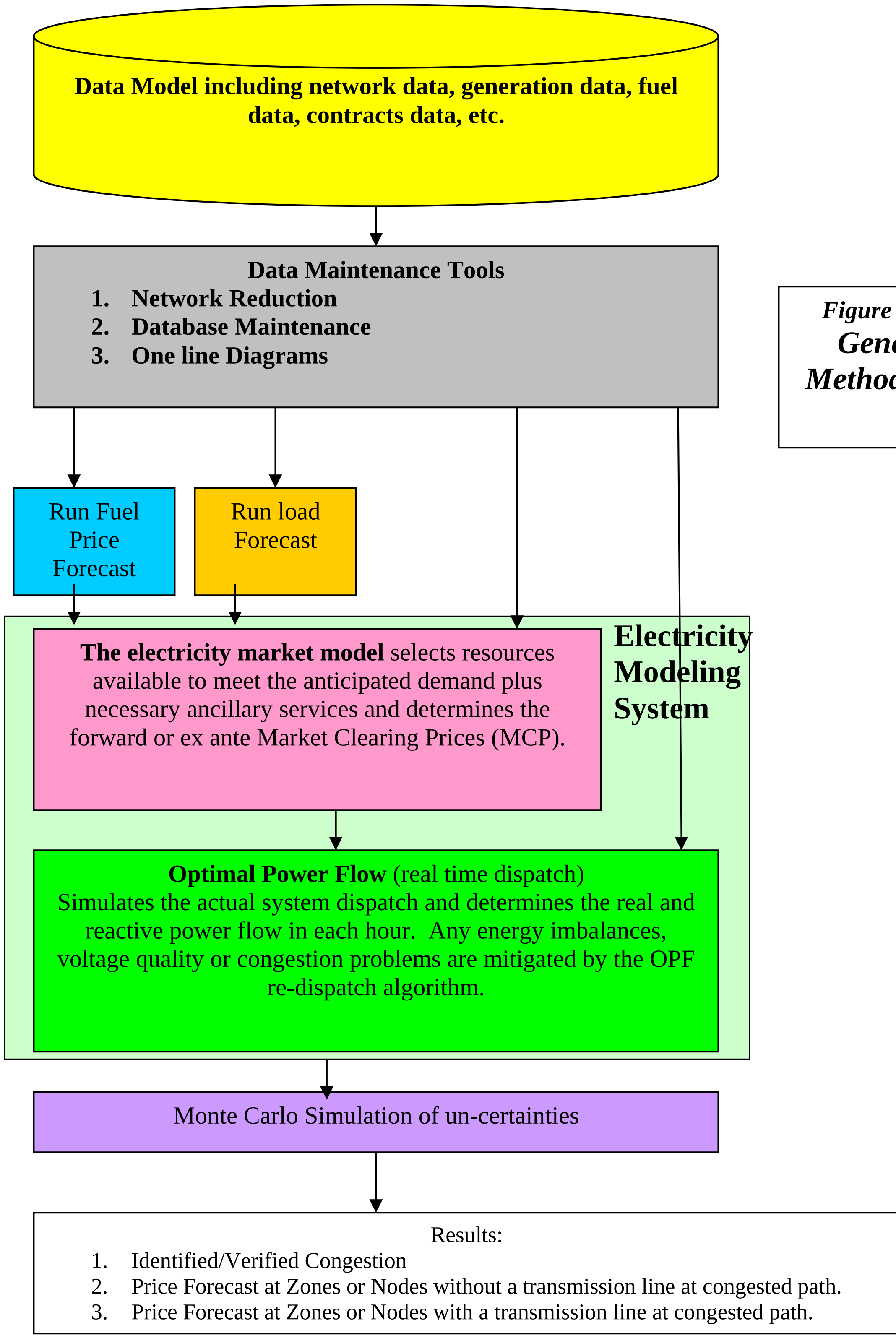


Figure EX 1-
General Methodology

The recommended vendors are result of a screened process conducted by assigned consultant based on industry knowledge and experience. The major criteria factors in this screening included; vendor's track record, number of delivered commercial systems in use, industry acceptance, product support, product record, and other similar areas.

Table 1 summarizes major findings for the load forecast tools reviewed.

Table 1- Comparison of the Products for the Load Forecast

Vendor	Product	Can Forecast for Multiple User-defined Regions	Time Frames up to 20 years	Economic Projection in Modeling	Weather Effect
Henwood	RACM	Yes	Yes	Yes with scaling	Yes
PredictPower	LoadForecaster	NERC Sub-regions	Yes	No	Yes
Siemens/NewEnergy	NOSTRADAMUS	Yes	Yes	No	Yes
Tesla	TESLA	Yes	Yes	Yes	Yes

Tables 2, 3, and 4 summarize characteristics and applications of the identified tools for the Electricity Modeling Systems.

Table 2- Availability of major functionalities by recommended vendors

Provider	Product	Electricity Market Simulation					Real Time Dispatch and Optimal AC Power Flow				
		Nodal Price	Emission Price	Zonal Price	Ancillary Price	TCA	Nodal Price	Load Flow		OPF	Congestion & Dispatch
								AC	DC		
ABB	TRACE	Does not provide this subsystem				Y	Y	Y	Y	Y	Y
	GridView	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
EPIS	AURORA	Y	Y	Y	Y	Y	N**	N**	N**	N**	N**
EPRI	TRACE	Does not provide this subsystem					Y	Y	Y	Y	Y
	CAR	Does not provide this subsystem					-				
GE	MAPS	Y	Y	N	N	Y	Y	Y	Y	Y	Y
Henwood	PROSYM	Y	Y	Y	Y	Y	Y*	Y*	Y*	Y*	Y*
LCG	UPLAN	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
NEXANT	SCOPE	Does not provide this subsystem					Y	Y	Y	Y	Y
PowerWorld	Simulator	Does not provide this subsystem					Y	Y	Y	Y	Y
PTI	PSS/E	Does not provide this subsystem					Y	Y	Y	Y	Y
	TPLAN	Does not provide this subsystem					Y	Y	Y	Y	Y
	MUST	Does not provide this subsystem					Y	Y	Y	Y	Y
Siemens	PROMOD VI	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y

Table 3- Major Applications of Assessed Products

Provider	Product	Users	Comments
ABB	TRACE	EPRI	Pre-Season Security Assessment Study Team
	GridView	Unknown	Unknown
EPIS	AURORA	Numerous generation and marketing and trading companies	It has been used for price forecast and asset valuation.
EPRI	TRACE	Self	Pre-Season Security Assessment Study Team
GE	MAPS	Numerous Transmission Companies	Transmission Planning
		PJM	Reserve Requirements Studies, Generator Unit Un-Availability Studies
		NY ISO	Generation Expansion Studies
		ISO NE	Reliability Studies
		MISO	Transmission Expansion and Reliability Studies
Henwood	PROSYM	Numerous Generation and Marketing and Trading Companies	Price Forecast, Asset Valuation
LCG	UPLAN	Numerous Generation and Marketing and Trading Companies	Price Forecast, Asset Valuation
		Regulatory Agencies	Litigation
NEXANT	SCOPE	Transmission and Generation Companies	LMP Calculations
PowerWorld	Simulator	Generation and Transmission Companies	LMP Calculations
PTI	PSS/E, MUST	ISO NE	Reliability Studies
		NY ISO	Reliability Studies
		Numerous Transmission Companies	Transmission Planning and interconnection studies
Siemens	PROMOD VI	Some Generation and Marketing and Trading Companies	Price Forecast, Asset Valuation

Table 4- Summary of the Applications to the Objectives of the Study

Product	Policy Level Analysis Y= Yes, N=No	Assessment of Current Bottlenecks N= National, R= Regional & ISO, S= State	Bottleneck Assessment Based on Physical Limitation Y= Yes, N=No	Bottleneck Assessment as a Result of Changing Market Dynamics Y= Yes, N=No	Forecast of Bottlenecks for next 10= 10 Years, 20=20Years
TRACE	N	N, R, S	Y	N	10, 20
GridView	Y	N, R, S	Y	Y	10, 20
AURORA	N	At this point is only Pipeline based for regions.	N	Y	10, 20 if used with one of the capable power flows
TRACE	N	N, R, S	Y	N	10, 20
CAR	-	-	-	-	-
MAPS	Y	N, R, S	Y	N	10, 20
PROSYM	Y If with PowerWorld	N, R, S	Y if implemented with PowerWorld	Y	10, 20 If used with PowerWorld
UPLAN	Y	N, R, S	Y	Y	10, 20
SCOPE Simulator	N	N, R, S	Y	N	10, 20
PSS/E, MUST	Y	N, R, S	Y	N	10, 20
PROMOD VI	Y	N, R, S	Y	Y	10, 20

Transmission bottleneck assessments based on utilizing these tools will require tremendous amounts of modeling data. The preparation and maintenance of these data will require a substantial amount of effort. The effort required for data preparation and maintenance has always created the following challenges for in-house software tools:

- Cost justification for the tens of working years required for data preparation
- Availability of (and schedule for obtaining) the required data
- Conflicts of interest and legal issues related to data ownership

The general vision of this assessment for obtaining and maintenance of modeling data is based on assumption that the studies and analysis can be conducted for separate regions as:

- Eastern Interconnection. The northeastern region contains more mature markets. However, modeling of markets like PJM, NY ISO, and ISO NE is quite complex from modeling data point of view. This assessment assumes a separate model for Midwest region because the electricity market in this region is in an early state of development.. As the Midwest market matures, additional data and alterations to existing data will be required. To minimize the impact of these changes, the Midwest region is modeled separately. This report assumes that the Northeast and Southeast regions can be modeled together for ease of modeling maintenance activities. The capability of handling large number of buses by available products supports this assumption.
- Midwest Interconnection
- Western Interconnection
- Southern (or ERCOT) Interconnection

It is also assumed that the data for each region will be available in some kind of standard format (IEEE, PSS/E, etc.) from one of the following resources:[1]

- Corresponding ISO/RTO
- The regions NERC organization
- EIA
- Data vendors

The estimated (one time) cost for purchase and integration of the recommended modeling system in this report is $5,000,000. This estimate includes software, hardware, project management, and integration.

The total annual budget for a modeling system to assess transmission bottlenecks utilizing the modeling tools assessed in this report is estimated at $1,870,000[2] annually, and will require an estimated 34,000 person-hours of effort annually.

In a final assessment, the report identifies the following major gaps regarding the tools that considered:

1. Source Data

The sources for the required data need to be specified based on identified information and requirements defined in this document. Initially the availability of the data requirements from identified sources needs to be assured. The format of the available data needs to be identified. This format has to be matched with the capability of the considered vendors. During the implementation, some development might be required for the translation or reformatting of data. This activity can be quite labor intensive if the following issues are not considered in the implementation plan of the data:

- Vendors' database management tools
- Acceptable formats to vendor
- Specific tools data requirements
- Data format from resources
- Available regular and boilerplate data from vendors

2. Functional Gaps

- One of the major gaps in satisfying the functional requirements is the availability of the subsystems for Electricity Modeling System from a single vendor. The majority of the providers offering market modeling tools do not also offer optimal power flow tools. The challenges and gaps in the implementation of these systems include: Time domains and frequency of calculations. The products evaluated use different tools and software approaches for managing the execution time and frequencies. These tools must be synchronized to function in a coordinated fashion with one another. Compatibility among modeling tools is essential, especially in the areas of data format, data requirements, and data maintenance tools. The main challenge lies in ensuring compatibility among the required data. This compatibility should enable the users to enter and maintain the data only in one place.

The majority of the providers do not support one or more of the following functional features:

---

[1] Review of data availability to support transmission bottleneck assessments is beyond the scope of this report.
[2] Calculated assuming 2000 hours per year for a person at average price of $55 per hour.

- Fuel constrains modeling in the Electricity Modeling System.
- Modeling of bilateral contracts in the Electricity Modeling System.
- Development of a new ramping model based on identified detailed requirements might be needed. This module would become part of the Electricity Modeling System.
- Additional functionality through inclusion of statistical factors for generation outage scheduling module.
- Modeling of global warming and emission constraints, although potentially important for this assessment, are not fully supported by majority of the providers.
- Special software needs to be developed to support price responsive demand and dispatchable load programs.

Recommended solutions for addressing the identified gaps are discussed in the report.

Table of Contents

1. Introduction

In November 2002, KEMA Consulting was assigned by Lawrence Berkeley National Laboratory to perform a study that assesses existing commercial tools in the U.S. market that might be used to help support future DOE assessments of national interest transmission bottlenecks, consistent with recommendations in the DOE National Transmission Grid Study. The tool or tools must be capable of supporting studies of power systems transmission, energy, and ancillary services and markets as well as trading behavior. This assignment consists of the following tasks:

- Task 1: Requirements Identification/Alternative Methodologies
- Task 2: Provider/Product Identification
- Task 3: Evaluation and Recommendations

This report presents the results of the study for all of the above tasks, and provides the results of the following activities:

- Study existing related documents, including reports; articles, etc. to prepare for identifying the definitions of transmission bottlenecks and functional and modeling needs of the possible alternative solutions and methods that can assess bottlenecks.
- Review alternative definitions of bottlenecks
- Identify and analyze alternative methodologies that could be used to assess bottlenecks
- Provide an Interim Report to LBL
- Provide a list of the entire well-known U.S. or foreign products, tools, and vendors that provide the alternative methodology/methodologies and required data modeling.
- Identify the input data, time and effort that will be required to apply these models to assess bottlenecks of national significance.
- Evaluate the vendors and their products.
- Identify gaps/deficiencies in available models (functions and data).
- Prepare a Final Report (this document is the final report)

As part of activity one the documents from different ISOs and RTO's (e.g. PJM, CA ISO) regarding the transmission and congestion issues were studied and analyzed. Some of the major observations from this analysis are presented in Appendix A of this report. The findings from activities two to eight are presented and reported in the following sections.

2. Definition(s) of Bottleneck

The goal of this assignment is to review existing analytical tools and methods that might be used by DOE in assessing national interest transmission bottlenecks. In achieving this goal, reports from numerous studies were used as references. These references are included in the reference list provided in Appendix B of this report. Considering the National Transmission Grid Study report and these other sources of information, the following is the working definition of *"national-interest transmission bottlenecks"* that has been used in this assignment*:*

Transmission bottlenecks that potentially effect national interests are conditions that can:

- Create congestion that significantly decrease reliability,
- Restrict competition,
- Enhance opportunities for suppliers to exploit market power
- Increase prices to consumers
- Increase infrastructure vulnerabilities.
- Increase the risk of blackouts.

Based on KEMA Consultant's understanding, the assessment of a bottleneck requires quantifying the reliability and economic impacts that they create, as well as those that would be avoided, if the bottleneck is removed or reduced. This can be achieved by a set of tools that identify the price of electricity in any specific location and assess the physical constraints or bottlenecks. These prices can be used in assessing the cost of a bottleneck to the consumer as one aspect of the national economic impact of bottlenecks. In any study of bottlenecks and of options to relieve them both of these activities, i.e. reliability and economic assessments, must be conducted in order to evaluate the costs of bottlenecks and benefits of relieving them.

For the National Transmission Grid Study DOE used the Policy Office Electricity Modeling System (POEMS) to conduct an initial assessment of the U.S. transmission system. POEMS is a full-scale national energy model designed specifically to examine the impacts of electricity industry restructuring.

The model includes significant economic, regional, and temporal details that are needed to analyze the economics of interregional trade. POEMS aggregates individual transmission lines to create a network of transmission paths that connect 69 sub-regions. The model represents the transmission system as a highway system, a series of paths between regions with a fixed amount of transmission capacity along each path. Trades are executed among the model's sub-regions based on the relative costs of generation in each sub-region as well as the costs of executing each trade. POEMS is a very important tool for assessing the economic consequences of electricity trade and identifying major transmission bottlenecks. However, it does not explicitly represent the following functionalities:

- The physical flows of electricity over paths in response to the combined effects of all other flows on the system.
- Trade within sub-regions.
- Reliability benefits.
- Representation of price spikes due to tight supplies and constrained imports.
- Transmission addition to reduce congestion that lead to only small changes in generation costs, but the mere presence of additional transmission capacity creates contestability in each of the local markets that will curb potential market power and reduce prices to consumers.

The addition of more detailed and physically accurate representations of transmission power flows, along with a more detailed simulation of market behaviors would enable DOE to improve the precision and resolution of future assessments of transmission bottlenecks.

3. General Methodology to Assess the Bottlenecks

Based on discussions in the previous sections the main goal of this task is to identify a set of tools that in general can:

- Model the power system economy and flow characteristics
- Identify the bottlenecks (power flow constraints) for specific region
- Identify assets or resources (e.g. transmission lines, generators) or other alternatives and upgrades that can cause elimination of that bottleneck i.e. eliminating or reducing the constraints.

The results of this assessment can be utilized as input data for conducting business and national impact assessments. These assessments by nature need to be conducted for at least 20 years. The twenty years of assessment horizon is required to capture the following factors and ensure the accuracy of the results:

- Necessary data for conducting an accurate cost and benefit analysis during a considerable portion of the life cycle of the proposed solution that can eliminate the bottlenecks.
- Necessary data for payback calculations.
- Identify the bottlenecks in present of the other new development and construction projects. According to a recent study the time period required for the completion of a medium to large transmission project is 5 to 8 years (please see reports of London Economics to CA ISO reference 2 in Appendix B of this report). The twenty-year horizon of the assessment will ensure the modeling of these new assets in the studies.

The requirements identified for each subsystem in this report assure that the identified tool is capable of being used and creating results for the next twenty years.

Based on the above observations the following are the initial general requirements for the assessment tool:

- Methodologies that enable the users to identify/verify specific bottlenecks.
- Ability to utilize these tools in finding (forecasting) the price of electricity at the specific locations or zones for specific period of time. This price forecast shall be conducted for both cases of having the specific bottleneck reliever asset in and out of service.
- Ability to conduct the assessment studies for up to twenty future years in flexible intervals (hourly, daily, monthly, and annual).

- Ability to easily calibrate the models and subsystems of the tools.

The results of these computer software runs can provide the users with sufficient information to conduct further economic analysis and business case development for expansion or changes in a transmission system.

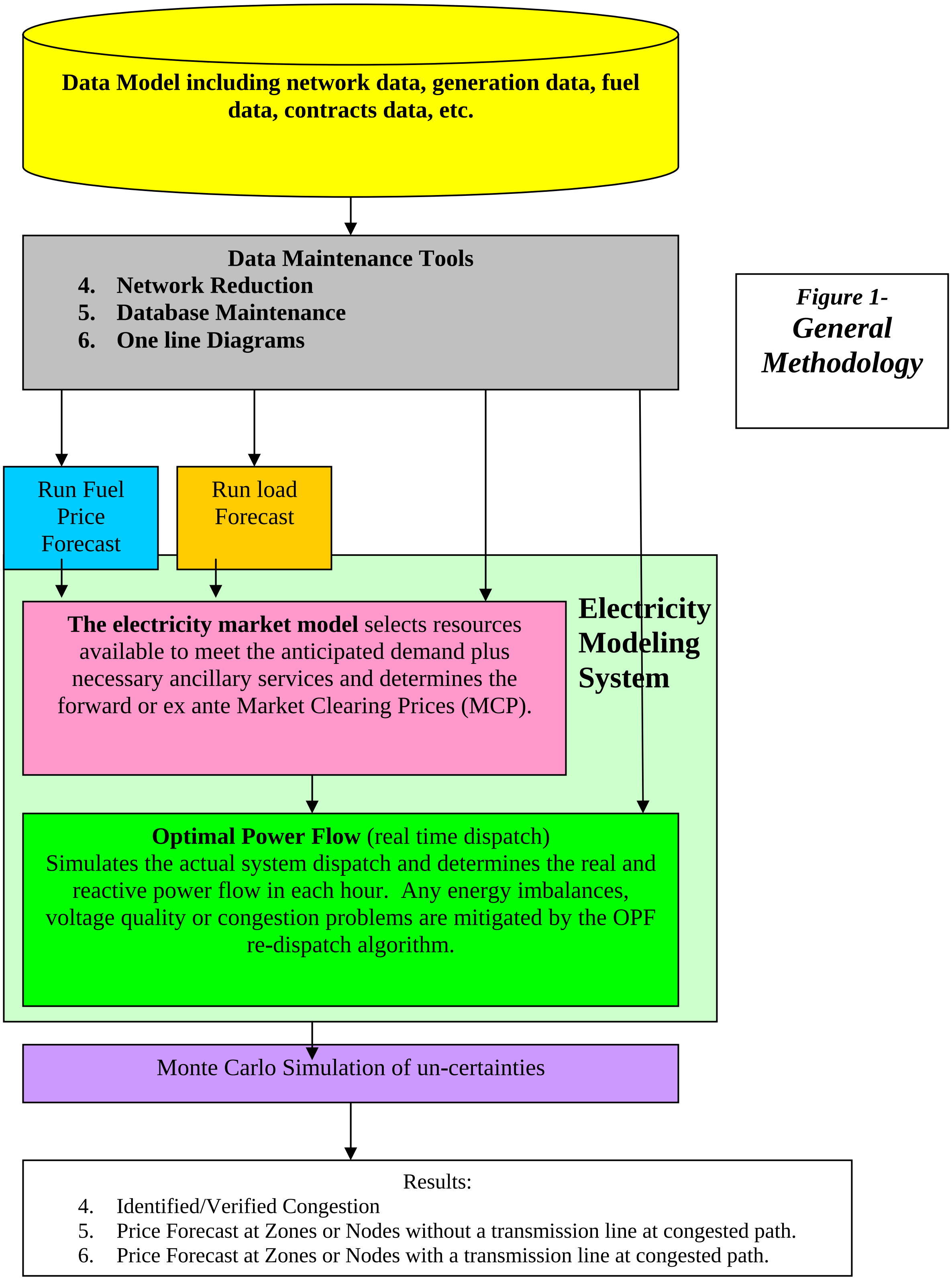
The general methodologies of conducting these studies are provided in the block diagram presented in figure one. The details for each methodology and available tools etc. are presented in the following sections of this report. The programs and subsystems identified in Figure one are the only software packages required by this methodology. Programs like short circuit study, transient and post transient programs are not required by this study. This methodology covers the steady state conditions of the power system. The short circuit, transient and post transient programs are usually run for transient stability analysis, which covers very short time spans (e.g. 2 to second time spans in milliseconds time steps).

In general the results of these studies need to cover the conditions of the system for at least next twenty years. These results are used for business case development and national impact studies. The data and information for the next twenty years can be categorized as following:

- Information and data that can be traced and forecasted using available tools in the market e.g. load, fuel price, hydrological conditions etc. These data and their forecasts are addressed in this report. It shall be noted that specifically the long term forecast tools are considered and studied since the time lines for the results of the forecast are twenty years and further.

- Issues that at this point one can only make assumptions based on existing information. A very good example of this is the rules that govern every market. At this point it is not known that how specifically the market rules in the year 2015 are going to be for PJM. However by considering and inclusions of all possible modeling features (at this time) and the flexibility of the modeling this issue is addressed in the requirements as much as possible. The models are also required to be modular so that future changes can be implemented easier.

The extensive detailed modeling techniques that are recommended in the following sections are provided to enable the users to capture the power flows and economic impacts as accurate as possible. The simpler models and methodologies are not capable of capturing the realistic bottleneck conditions. They also miss the major existing trend of price modeling i.e. Locational Marginal Pricing, which can be the only guide in identifying the national economic impact of the proposed solutions. The effects of the uncertainties in the proposed solutions are suggested to be modeled by a proposed Monte Carlo simulation tool.


Data Model including network data, generation data, fuel data, contracts data, etc.
Data Maintenance Tools
4. Network Reduction
5. Database Maintenance
6. One line Diagrams
Figure 1- General Methodology
Run Fuel Price Forecast
Run load Forecast
Electricity Modeling System
The electricity market model selects resources available to meet the anticipated demand plus necessary ancillary services and determines the forward or ex ante Market Clearing Prices (MCP).
Optimal Power Flow (real time dispatch)
Simulates the actual system dispatch and determines the real and reactive power flow in each hour. Any energy imbalances, voltage quality or congestion problems are mitigated by the OPF re-dispatch algorithm.
Monte Carlo Simulation of un-certainties
Results:
4. Identified/Verified Congestion
5. Price Forecast at Zones or Nodes without a transmission line at congested path.
6. Price Forecast at Zones or Nodes with a transmission line at congested path.

This assessment process involves and requires tremendous amount of modeling data. The preparation and maintenance of this data (if available due to conflicts of interest) will require a tremendous amount of work. The required effort for this data preparation activity has always produced the following challenges for in-house software tools:

- Cost justification for the tens of working years required for data preparation
- Availability schedule for the required data
- Conflict of interest and legal issues related to data ownership

The general vision of this assessment for obtaining and maintenance of modeling data is based on assumption that the studies and analysis can be conducted for separate regions as:

- Eastern Interconnection. The northeastern region contains more mature market modeling characteristics. Modeling of markets like PJM, NY ISO, and ISO NE is quite complex from modeling data point of view. This study assumes a separate model for Midwest region because the electricity market is in the evolving trend in this region. As the Midwest market matures, additional data and alterations to existing data will be required. To minimize the impact of these changes, the Midwest region is modeled separately. This report assumes that the Northeast and Southeast regions can be modeled together for ease of modeling maintenance activities. The capability of handling large number of buses by available products supports this assumption.
- Midwest Interconnection
- Western Interconnection
- Southern (or ERCOT) Interconnection

It is also assumed that the data for each region will be available in some kind of standard format (IEEE, PSS/E, etc.) from one of the following resources:

- Corresponding ISO/RTO
- The regions NERC organization
- EIA
- Data vendors

The preparation of the data for the recommended tools in this report requires thorough knowledge and experience of power systems modeling and database building. The process of building data model includes the following critical tasks:

- Decision on study intervals. This study is recommending tools that can produce results for hourly, daily, monthly, and annual intervals. However depending on region or market behavior and rules the intervals of the subject assessment can be different. For example there might be study cases that would have to be run in hourly interval for the whole year(s), i.e. 8760 hours per year. The volume and effort of input data preparation for these cases are tremendously higher than cases that daily or monthly intervals are needed for them. There are markets that support (or intend to support in the future) scheduling intervals for less than one hour. The ability to conduct simulation for these situations (that involve less than one hour intervals) can be a software integration issue. The two major factors regarding these situations are the support from software packages and availability of data.

- Decision making, on the control areas and voltage levels to be considered. E.g. 765 kv to 69 kv, and DC lines.

- Decision on the total number of buses.

- Decision on generation types aggregation and corresponding data. E.g. gas, oil, coal, hydro, nuclear, pumped storage, synchronous condenser, and jointly owned units.

- Decision on selection of the sources of data.

- Establishment of a process to make the modeling of the systems useable for the future studies.

- Selection of data maintenance tools

The following sections provide detailed description regarding each one of the functions in the general methodology. The detailed modeling and data requirements for each function are provided in the corresponding section and/or section 7. The estimates for costs and human resource estimates are based on personal experience of the assigned consultant. The recommended vendors are result of a screened process conducted by this consultant based on industry knowledge, experience, and following criteria:

1. Vendor’s Track Record

- Number of delivered commercial systems in use. There are numerous products available that are in academic form and have not had commercial use history. These kinds of products and vendors were not considered in this assessment.

- Industry acceptance. Especially among ISO/RTOs, transmission, and generation companies. A product is considered “accepted” when it is used by these entities continuously or in numerous occasions.

- Product support.
- Project management and delivery procedures
- Delivery Record
- Warranty.
- Schedule reputation (if they deliver on time and as scheduled).

2. Vendor's Product Record (e.g. specifically as a planning tool)

- Functionality. In some occasions even if partial functionality was fulfilled but product has been used in the industry, some discussion regarding the product is provided.
- Product road map. The leading commercial software providers maintain a product road map for their releases. These releases usually contain the new enhancements and fixes for the recently identified problems. The product road map is critical for maintainability and/or enhancement of the selected product.
- Functionality strengths and shortcomings. The products recommended by this report are all viable packages. The development and commercialization of these products have cost the providers years of work power and other expenses. The specified shortcomings are in general major areas that can be enhanced.
- Platform and Configuration (i.e. non-proprietary)
- Standards compliance. These are general industry standards, for example if the providers used a major standard database manager like Oracle, Excel, Access, etc.

The vendor evaluation for this study was conducted without soliciting any input or review from the vendors. All of the information and data provided in this report are based on experience and/or previous engagements of the assigned consultant.

4. Load Forecast

Majority of the bottleneck analysis studies and tools depend on numerous statistical parameters. One of the most influential of these parameters is the long-term load forecast. The long-term forecast of the load is one of the very critical assumptions and inputs to almost all of the functions in these studies. For example Load Forecast provides the solid base for understanding price movements. The long-term load forecast needs to have the same accuracy of the proprietary load forecasts done by load providing electric utility companies (using their internal, proprietary data) for their own service areas. It also needs to be consistently more detailed than ISO forecasts in terms of being able to forecast specific loads rather than aggregated models. The following are some of the characteristics of this load forecast:

- Provided for all of the NERC Regions, major Control Areas (TVA, etc.), ISOs and RTOs, price hubs, or any user-defined combination of the above.
- Support variable time frames and formats i.e. Long-term: 1 day to 20 years - hourly or daily, Peak and off-peak
- Include long term economic projections
- Incorporate areas' proprietary weather or real-time load data
- Developed based on one or a combination of following techniques, multivariate regression analysis, structural time series, and include seasonality

The Load Forecast (LF) function provides hourly load forecasts based on, but not limited to, historical load, and weather data and forecasted weather and economic data. The output of the LF function is usually available for use via the full graphic user interface, and can be used by other functions. The model of a good Long Term Load Forecast is accurate to within the limits of statistical and econometric models; forecasts of weather and economic activity that drive the LF are likely to have errors, which means that actual loads will deviate from forecasted loads. The modeled loads need to be within an acceptable range of the actual loads after controlling for weather and economic activity. Thus, an important functionality in a LF package is that the performance of the model can be assessed easily and quickly so that adjustments can be made appropriately. The economic components of the model structure are to conform to good economic theory and practice so that the system can also yield information that is useful for the ultimate goal of this assessment.

Certainly weather is extremely important in the short run, while economic and secular data play a stronger role in the medium and longer run. The effect of weather does not disappear in the long run nor does economic activity disappear in the short run.

The LF function is usually executable on demand for a user defined study period to forecast hourly loads. There is a user-selectable option to execute LF automatically each hour in a single-day forecast mode, to update and refine the current day's load forecast based on the most recent load data. Excessive deviations between actual and forecasted load and weather data are reported.

Using long term LF one can forecast loads separately for individual forecast areas where each area can have a separate weather pattern. The service area load is the sum of the area loads.

In the available advanced LF functions the need for user input is essentially limited to the input of previous load and future weather forecast data. Any other inputs are related only to executing control and editing. The load forecast functions in the market are capable to import weather data and /or economic from an external file as provided by a forecasting service.

The commercial Load Forecast functions are capable of storing historical load, weather, and economic data for future load forecast purposes. The following capabilities are provided:

- Manual or automatic retrieval of data for input to LF
- Automatic storage of new data as it becomes available
- Interactive access to historical LF data profiles for tabular and graphical display
- Interactive editing to support maintenance of LF data profiles.

A multi-user capability is provided for the support of numerous simultaneous studies. Multiple users have their own working areas. Every user can maintain multiple working cases. These working cases can be stored as a save case for permanent storage. One of the save cases is usually assigned to the Current Load Forecast as the basis for retrieval of load forecast data by other functions. Usually a facility for the management of the working areas and save cases is provided. The user is able to make changes to disposable working areas without affecting the original save cases. Interaction between users is done only via save cases.

Through provided features the available LFs in the market enable the user to manually search through historical LF profiles using tools that will facilitate a search for profiles that will match the current day situation. The user can view these profiles and load them in a user's working area to be used as a basis for further load forecasting. The user is also enabled to initiate an automatic adaptation of a selected historical profile based on differences between historical weather variables and the current weather forecast. The user is also be able to copy one day's (or bracket of time) forecast to another day (or bracket of time).

The user can also edit load forecasts as well as weather and economic forecasts by either editing individual hourly values or entering parameters that will reshape daily curves. Graphical editing techniques are used in most of the commercial products. The user can reshape a forecast by specifying a scaling factor (multiplying all forecast values by a number) or a bias factor (add a positive or negative number to all forecast values). As an alternative to specifying a scaling factor, some providers can support this by entering a new peak load value. Individual changes to weather and economic forecast input parameters are usually permitted.

Flexible tools in the available LF products are provided for entry of weather forecast data. As an example in most of the products one can predefine blocks of hours during a day for which weather data will be entered. The user can override block values by hourly values or directly enter hourly values.

The LF functions in the market compute error statistics using the actual load data and the forecasted load data. An error corrective feature is provided to adjust the forecasted load for the remaining period of time. The adjustment is usually calculated and is a function of the error between the actual load and the forecasted load from the previous times.

The available LF functions usually utilize one or a combination of the following algorithms:

- Pattern Matching Forecast
- Weather and/or Economic data Adaptive Forecast
- Neural Network Forecast

The suppliers usually provide and develop the initial load data models.

The suppliers usually supply all programs, off-line and on-line, that are necessary to develop new load models. Also, the suppliers provide any graphical tools necessary for model identification and parameter estimation.

The LF functions can support multiple weather variables per load forecast area. The modeled weather variables typically include:

- Temperatures (ambient, dry bulb, heating degree days, and dew point)
- Rainfall
- Cloud coverage
- Wind speed

- Wind direction.

The relative humidity is calculated from the ambient and dew point temperatures.

The user can select the weather variables to be used in the search for the best load pattern match. In addition, the capability to weight variables more heavily than others is provided.

Economic data at different levels (e.g. the state, metropolitan area, or county level) is usually available at best on a monthly basis, in the case of employment, and on a quarterly or annual basis for other kinds of information. This frequency usually does not pose a real problem since economic activity can be considered fixed in the very short run. In order to incorporate levels of economic activity into the model in the short run (peak loads or daily energy), and changes in activity as the short run unfolds into the long run, the appropriate economic variables can be converted (from monthly, quarterly, annually) to daily values which remain constant until a new value emerges, employment in the next month, for example.

The constancy of economic data in the very short run, combined with its variability in the medium and long run, allows the use of the same model as the time horizon unfolds. Weather data can be used in a similar way. As discussed above, weather is certainly a major driver of short to medium load, and weather data is available as a forecast to feed into the driver side of a load or energy-forecasting model as a set of assumptions. Longer run weather forecasts are much less certain, even for a month ahead, let alone a season, year, or decade. For these planning periods forecasters incorporate the concept of "design weather" into the model. While each day or month can differ in accord with the design characteristics, the design pattern can be held constant for planning purposes. In fact, atypical weather patterns as well as typical or design patterns can be incorporated into the model for purposes of comparative analysis. So, analogous to the way in which economic data is fixed in the short run, weather patterns can be fixed in the longer run. It is the pliability of the model drivers that allows the use of the same model structure over very different timeframes.

Economic and weather data can be purchased from economic and weather forecasting vendors and are provided at the state, and county levels for subsequent aggregation into zones.

In most of the commercial LF functions the capability is provided to perform an after-the-fact analysis that would compare actual and forecasted load and weather data for each area. Significant differences are usually summarized.

The LF functions acceptable in the market are capable of producing load forecasts for hourly intervals with a percentage error of less than 2.5%. This error is defined in terms of the difference between actual values and forecasted values (using perfect weather forecast data) for any hour of the forecasting period.

Most of the available commercial load forecast packages could produce load forecast down to required details (i.e. NERC Regions and sub-regions, major Control Areas (TVA, etc.), control areas, ISOs and

RTOs, price hubs, or any user-defined combination of the these). Unlimited sizing of geographic regions usually is supported by of submitting batch (software execution) jobs for each region. Usually batch-processing capability allows the user to select which regions are desired for training or forecast in one (batch) run. Users can also specify the order in which it is desired to make the runs. Using specific software tools, users have the capability to execute multiple forecasts or training runs at a specific time period, e.g., each evening automatically. This study has provided the practical applications or experiences of the providers (if any, in the following sections) regarding this issue. It shall be noted that although the sizing might be unlimited the availability of the historical data for the forecast is very critical in creating results.

4.1 Load Forecast Providers & Products

The electric (long-term) load forecast has always been one of the key drivers of electric utilities' planning activities. Utility planners implemented and tuned their own load forecast packages based on standard software from external providers. The algorithms used in today's commercial packages are mostly based on methodologies and/or experiences that were gained from the vertical utilities' planning departments. With the advent of restructuring in the North American electricity market, the forecast of domestic requirements is an input that enables the pursuit of future market designs, options and electricity trade decisions. These issues have enforced the need for more flexible commercial load forecast packages. Thus the load forecast packages in the commercial market could be categorized mature even if they are provided by (some) younger providers and have some recently developed new features.

The leading vendors in providing long-term load forecast include:

- Henwood
- PredictPower
- Siemens/NewEnergy
- TESLA

It shall be mentioned that many other companies provide load forecast for the desired time frame of this assessment as a service. This assessment did not investigate those providers. The scope of this study is to assess available tools and products.

There are some companies that provide load forecast packages for shorter terms (day to five years). Electricity traders usually use these products. The most well know among these lines of products is AcuPower Load Forecast from E-Acumen. These kinds of products were not considered by this study since they do not address the required time frame of 20 years and/or lack of inclusion of economic data.

4.1.1 Henwood

Henwood's EnerPrise™ Software module, RACM™ provides load profiling, and load forecasting in addition to many other functions. This load forecast is based on weather changes. Henwood's load analysis module generates hourly load shape data that can be used for simulation modeling or statistical analysis, and calculates monthly coincident peak loads and energy requirements in its market demand forecasts. Additionally, the user may select and/or modify load forecasts for a variety of aggregation levels: NERC Region, NERC Sub-Region, Control Area, Transmission Zone, and Utility. The hourly results can be downloaded in several formats or displayed graphically as either chronological load curves or load duration curves.

Utilizing batch processes in the providers software program, capability for unlimited geographical regions down to individual load serving company levels can be supported. Existing reports from actual applications indicate that Henwood model is capable of predicting load down to 288 load serving entities. The Henwood's load analysis module enables users to access 8 years of historical hourly data for 288 load serving entities in North America. This load database is combined with Henwood's proprietary load shape algorithms and 10-year load forecasts for approximately 290 individual load areas to provide data for this platform.

Henwood announced the release of the latest version of its EnerPrise software retail and load module, RACM, including technology that handles weather stress scenarios and capability to work in sub-hourly markets (such as ERCOT) in second quarter of 2001.

Henwood’s EnerPrise software is licensed by over 150 companies worldwide and supported by a foundation of client support. Henwood has about two decades of power industry experience, for North America, Europe, Australia, and Asia. Global Energy Decision Inc has recently purchased Henwood. This product is used by Henwood for providing on line services of load forecast which has tens of subscribers.

4.1.1.1 Major Strengths and Shortcomings of RACM

Some of the major strengths of this product include:

- Filtering by NERC Region, NERC Sub-region, Control Area, Transmission Area, and Utility. This feature can facilitate the maintenance of data. Data maintenance and preparation is probably one of the most time consuming activities of this assessment. Any tool or service from the providing vendor in this area can be very instrumental in improving the efficiency of the work power. This feature also creates flexibility in application of product for study’s focus area.

- Numerous weather analysis related features like, weather stress analysis, Graphical views of weather variability, and ability to create load forecasts consistent with specified weather scenarios. All of these features can improve the efficiency of the work power in their data analysis and assessment activities.

- Drop down menus to aid data filters. This feature facilitates the maintenance of data.
- Chronological load curve graphing. The graphing is always useful for the users in their analysis and tuning activities. E.g., with load curve graph the actual versus forecast comparison can be more visible.
- Load duration graphing. This feature facilitates the detail analysis of duration.
- Graphic and tabular output. This feature simplifies the work of analysts in search or analysis of data.
- User selected date range to aid data queries for export, graphing and analytics. This feature simplifies the creation of the report by the analysts.
- Calculates coincident peak loads and energy. Coincident peak loads capture the diversity within a group of utility loads. In an area that consists of multiple load serving entities the peak load of each entity can occur during different hours. This is critical in calculating the needed generation for the area. According to Henwood in a typical year, the coincident peak will typically be 3-6% lower than the non-coincident peak in any given NERC sub-regions. Coincidence has a bigger impact for a larger geographic territory in a study's aggregation levels. This feature can improve the accuracy of the results.
- Henwood claims to have historical hourly load data from 1993 for different areas. They also claim to have load data for 250 load serving entities. These data is necessary (as input data) for running these programs. This data can cut the time and effort in search and preparation of model.
- Data download in EEI, chorological, and daily. The EEI (Edison Electric Institute) format is a standard format for load data. This feature can be useful for analysts in data analysis and also
- Minimum, Peak, GWh, and percent change data. All of these data could be used by other subsystems in enhancing the validity of the study.

Major shortcomings of this product include:

- Utilization of load growth factor rather than economic data. However if the future economic forecast is available it can be interpreted and included in the load growth factor. This feature is a simplistic way for inclusion of the economic data in load forecast.

- Henwood has been marketing this product mostly for retail load forecast. However they also claim that it can be used for this kind of transmission assessment.

4.1.2 PredictPower

PredictPower's form/fit modeling solves the problem of "local minima" (A function f(x) has a local minimum at x_0 if and only if there exists some interval I containing x_0 such that $f(x_0) \leq f(x)$ for all x in I, in this case we are finding the minimum of the prediction error), and utilizes custom-built models to capture expert knowledge using non-linear parameterized models. These algorithms can be viewed as a method of combining of neural network and non-linear regression techniques. The software uses proprietary data not available to the public, such as historical load data broken into local blocks, instead of aggregated system-wide. In addition, the official load forecasts do not represent the direct output from the numerical algorithm. The product is called LoadForecaster.

Load Forecaster provides regional load forecasts for each sub-region within each NERC region. Forecasts are presented in terms of absolute total load, change in load from the previous day, and deviation of load from the climatological norm. For each sub-region, data for the forecasted load for the day, for the peak period (0700-2200) and on an hour-by-hour basis is provided.

This provider is the load forecaster for the CA ISO.

4.1.2.1 Major Strengths and Shortcomings of LoadForecaster

The strengths of this product include:

- The field experience of this provider in CA ISO is very credible. This vendor has indicated that they are in process of starting to provide similar system for an ISO in northeast United States.
- Good error of solution. This conclusion is based on the results from the CA ISO load forecast activities. Accuracy and error of load forecast is always an issue for the commercial load forecast providers.

The major shortcomings of this product include:

- Much emphasis on similar day load forecast. This feature although is good in improving the accuracy of results it cannot be the sole success factor for obtaining viable results. Economic data inclusion is very critical for a viable load forecast.
- The provider has more history as service provider compared to delivery of the whole package.

4.1.3 Siemens/New Energy

This provider offers two lines of products for long-term load forecast. The first Load Forecast product is part of Spectrum/Power CC product line. This product determines minimum and maximum demand, total energy and load duration curves by each basic time interval for one or several years in advance. The algorithm is a stochastic model building according to Box-Jenkins methodology. This algorithm includes temperature influence modeling, holiday adjustment and flexible forecast error analyses.

This product has been used for the Long/Mid Term Load Forecasting (LMTLF) functions. It generates and updates load forecast for a system for whole planning period.

The function calculates, optionally, for one or two tariff periods, the following quantities:

- Weekly/Monthly/Daily Peak Powers
- Weekly/Monthly/Daily Minimum Powers
- Weekly/Monthly/Daily Energies
- Weekly/Daily Central Moments (1-8), and Cumulants (1-8)
- The LMTLF function can be executed in two modes of Stochastic Model Building, or engineering mode i.e. optimal model parameters determination,
- Long/Mid Term Load Forecasting for each time-series based on previously determined model parameters

This product is available in multiple computing environments, including as a desktop application, as a network server, or as a component integrated within a larger system. No specific benchmark is available regarding the performance of this product. This product has been implemented as long-term load forecast for SBB Swiss and also Qatar long-term production planning systems. The mid term applications of this product include a subset of the Energy Management and Information Systems Customers.

Siemens offers another product in this area called NewEnergy NOSTRADAMUS. This product employs neural network based programming and mathematical techniques that train a network of inputs and outputs to recognize relationships. Once the network “learns” these intricate associations, it can apply that knowledge to accurately forecast demand variables. NOSTRADAMUS gives you the capability to generate both daily and hourly forecasts. Some of their clients that use this product include, Entergy, DTE, Conectiv, El Paso Merchant, LG&E , and GPU.

This vendor claims that NOSTRADAMUS forecasts for unlimited geographical regions down to individual load serving company levels. This claim is supported by AutoNOST™, which provides the batch processes in the software program. No practical experience in this area is reported. AutoNOST™, product, provided as part of NOSTRADAMUS provides the capability to execute multiple forecasts or training runs at specific time periods.

4.1.3.1 Major Strengths and Shortcomings of PowerCC and NOSTRADAMUS

The major strengths of Spectrum/PowerCC product include:

- Long existence in the market (since early 80's as part of Control Data ARTECS systems).
- Strong product road map. This product is included in the release of the major EMS product that this provider markets. This issue improves the maintainability of the product for future years.

The major weaknesses of this package include:

- Lack of inclusion of economic data for long term forecasting. Inclusion of this data is very critical for long-term load forecast. Without this data the long-term forecasts cannot be accurate.
- Lack of planning study oriented capability for model calibration. The model calibration tools for a load forecast package are continuously used. They are very critical in facilitating the job of analysts for reducing the required time for calibration.
- Modeling capability to enable users to use it in economic studies. This tool has been mostly used as an EMS for off line studies. The users of this product are mostly system operation departments. This study requires tools that have strongly field power system planning history.

Major strengths of NewEnergy NOSTRADAMUS product include:

- User-friendly set-up of training and forecast parameters data and their entry. These features can reduce the consumed time by the users during the initial set up (training the system), and also data preparation.
- Logical organization of multiple forecast scenarios, which can reduce the time and effort of analysis for the study.
- Output data that is easy to use and access. The form of output data is available in curve or tabular formats that can be useful for accuracy analysis and general study.
- Extensive inclusion of weather data. This improves the quality of solution especially for shorter-term results.

Major shortcoming of this product is the lack of inclusion of economic data for long term forecasting. Since this product is based on neural network techniques it shall be feasible to include this factor as an input as an enhancement.

4.1.4 TESLA

The name of the company and also product is TESLA. TESLA's load forecast package consists of two major components:

- Forecasting module
- Weather correction module

The forecast algorithm is based on non-linear regression technique. It can provide operational forecasts based on near term weather forecasts, and in the same modeling environment provides medium and long-term estimates based on economic projections and alternative weather scenarios. One of the major algorithmic features of TESLA model is its treatment of the weather data. For example, TESLA recognizes the temperature effects as nonlinear variables, and the shape of the temperature response curve is itself dependent on other weather variables (e.g. humidity or cloud cover), recent weather history, time of day, type of day, day of week, and "calendar events." TESLA requires hourly observations of data on five major weather variables: temperature, humidity, cloud cover, wind speed, and precipitation. It also requires recent load data, of the appropriate periodicity (hourly or sub-hourly, depending on the model periodicity). In building a long-term load profile that includes typical, high-demand, and low-demand profiles, since this model contains a normal weather history, the typical profile is built based on normal weather and "most likely" economic and demographic projections.

TESLA was developed for own-area analysis for London Electricity (plc), in the United Kingdom. It is in use internationally. The following is a list of some of the customers of this product that use it:

- Commonwealth Edison, Inc.
- South Carolina Electricity and Gas, Inc.
- London Electricity,
- East Midlands Electricity (plc), (UK)
- SEEBOARD Electricity (plc), (UK)
- Southern Electricity (plc), (UK)

This product is available in multiple computing environments, including as a desktop application, as a network server, or as a component integrated within a larger system. According to a benchmark conducted by TESLA using an Athlon 700 MHz processor with 128 megabytes of 100 MHz RAM, the compute engine needed about 8 seconds to solve a half-hourly model over one year (17,520 periods).

This product has been in market since 1992.

This vendor claims that forecasts for unlimited geographical regions down to individual load levels are supported. No practical experience in this area is reported.

4.1.4.1 Major Strengths and Shortcomings of TESLA

Some of the major strengths of this product include:

- Tabular and graphical data visualization. This feature simplifies the work of analysts in search or analysis of data.
- Weather scenario generator. Generally speaking this feature and the other weather related of this vendor are quite sophisticated. This features help increase the accuracy of the short-term forecast. Weather plays some role in long term forecast also. The weather scenario generator is not as critical for long-term forecasts.
- Inclusion of economic data for long-term forecasts. This provider directly considers the modeling of economic data in their product. The modeling of this data is very critical for long term forecast.
- Forecasts based on partial weather data for long term forecast. This improves the quality of the forecast.
- This provider supports strong tools for model recalibration. The model calibration tools for a load forecast package are continuously used. These tools are very critical in shortening the calibration time and effort.
- Modeling capability to enable users to change the model specification, re-estimate it, and compare the performance of alternative specifications. This is very useful in improving the error of the forecast and also improving the required time for the result accuracy analysis.

The major shortcoming of this product is the lack of bigger customer base in the US. There are many experimental sites (e.g. NRG Energy, etc.) that are using this product on performance basis.

4.2 Load Forecast Data Requirements

The data requirements for the load forecast are in correlation with functional requirements as summarized at the beginning of this section. The following is a list of major data that is required:

- All of the historical load, and weather data as required by products design.
- This data can be available from ISOs, RTOs, NERC regions, EIA, etc.

The data gathering in this case is a one-time activity. The available commercial products provide automatic ways of inputting new historical data. Special attention is needed when the lowest level that the loads are modeled is defined in the system. The unlimited modeling level size (when supported), although increases the flexibility and accuracy, can make the data maintenance activities more complex. The more detailed modeling level (e.g. individual load level) can also increase the timing required for conducting the study since it is usually supported by automatically running multiple batch jobs.

Another source of data especially for control areas can be the data obtained by FERC form 714. The FERC Form No. 714 (FERC-714) collects information for the Federal Energy Regulatory Commission (FERC) from electric utility control and planning areas in the United States. This data will be used to obtain a broad picture of interconnected control area operations including comprehensive information of control area generation, actual and scheduled inter-control area power transfers, and load; and to prepare status reports on the electric utility industry including review of inter-control area bulk power trade information. This data can be one of the load forecast data sources for this assessment.

The data calibration for this subsystem is usually required during the following two periods:

- Initially when the model is installed. These activities involve the tuning of all of the input data and the program (algorithm) parameters to obtain lowest error in the forecast results. In addition this model calibration can be based on resolution for economic and weather data accuracy issues; and study area's (e.g. control area) historical load and model training.

- As part of on going activities the tuning of the model needs to be conducted. These activities involve the re-tuning of all of the input data and the program (algorithm) parameters to obtain lowest error in the forecast results. In addition model calibration can be based on resolution for economic and weather data accuracy issues; and study area's (e.g. control area) historical load and model re-training.

4.3 Comparison Table of Providers

Table 4.3.1 provides a comparison of support of the general requirements by the screened vendors.

Table 4.3.1

Vendor	Product	Can Forecast for Multiple User-defined Regions	Time Frames up to 20 years	Economic Projection in Modeling	Weather Effect
Henwood	**RACM**	**Yes**	**Yes**	**Yes with scaling**	**Yes**
PredictPower	**LoadForecaster**	**NERC Sub-regions**	**Yes**	**No**	**Yes**
Siemens/NewEnergy	**NOSTRADAMUS**	**Yes**	**Yes**	**No**	**Yes**
Tesla	**TESLA**	**Yes**	**Yes**	**Yes**	**Yes**

4.4 Purchase and Ownership Costs

The initial costs include the purchase and implementation expenses of load forecast function. The details of these costs are presented in table 4.3.1. This initial implementation is estimated to require half of a calendar year. The prices and hours accuracy is ±15 percent. These prices are not from a specific vendor, they are figured based on personal experience of the assigned consultant.

Table- 4.3.1

Item	Labor Cost in Working Hours	Approximate Price of Software in $
Load Forecast Software, including, license, integration, customization, etc.	-	500,000
Hardware	-	60,000
Specification and detailed requirement definition	500	100,000
Project management	1000	200,000
Data preparation	4000	600,000
Testing	200	40,000
Total	5700	1,500,000

The ownership cost is the cost of maintaining and operating of the software. This cost is on per year basis. In some cases the providers of this product only charge yearly license fee. In this case the initial cost does not apply any more. The typical yearly one user license for a package as defined in this report is about $50,000 to $80,000.

Section 3.0 of this report presented the initial modeling assumption for this assessment. According to that assumption the whole country is divided to the following study regions:

- Eastern Interconnection. The northeastern region contains more mature market modeling characteristics. Modeling of markets like PJM, NY ISO, and ISO NE is quite complex from modeling data point of view. This study assumes a separate model for Midwest region because the electricity market is in the evolving trend in this region. As the Midwest market matures, additional data and alterations to existing data will be required. To minimize the impact of these changes, the Midwest region is modeled separately. This report assumes that the Northeast and Southeast regions can be modeled together for ease of modeling maintenance activities. The capability of handling large number of buses by available products supports this assumption.
- Midwest Interconnection
- Western Interconnection
- Southern (or ERCOT) Interconnection

This study assumes four engineers (one for each area) for preparation, maintenance, and application of modeling data for each area. The detailed modeling inside each one of the above regions (i.e. NERC Regions and sub-regions, major Control Areas (TVA, etc.), control areas, ISOs and RTOs, price hubs, or any user-defined combination of the these) is to be defined by these engineers. It shall be noted that at the beginning when the software is installed more (one or two) engineers might be required for covering the calibration and start up process. The calibration typically takes about three months after the data is prepared. Some of the major responsibilities of these engineers include:

- Initial and periodical data gathering
- Running of the system for assigned assessments
- Calibration of the system
- Coordination of the activities and database contents with other subsystems installs and upgrades.

The computer software including LF functions and database maintenance software will require one full time software engineer. Some of the major responsibilities of this engineer include:

- Installation of software and data files.
- Installation of software upgrades and patches
- Ensuring that the system operates (runs) during working or software running times.
- Support and problem shooting for the four users of the system.

- Participation in initial and on going data installation and upgrades
- Participation in calibration

For software maintenance and upgrade one can purchase an annual maintenance package.

5. Fuel Price Forecast

Fuel price forecasts for the period of study will be required. This data is used as input to market simulation module. The specific forecasts for the following types of fuel are required:

- Gas
- Oil
- Coal

5.1 Gas Price Forecast

Gas prices fluctuate 40-50% or more over the course of just a few weeks or months. The gas market is very volatile. Weather always has been and will be one of the primary drivers behind changes in natural gas prices. The gas prices move on weather news all of the time. The gas prices also move on changes in gas storage levels. There are certainly other factors that impact natural gas prices but the fundamentals of weather and storage are two of the most important. Unfortunately at present time there is simply no off-the-shelf tool that with some input data from these factors can forecast gas prices. However the gas price forecast as a service is available from commercial and government sources. It is this consultant's recommendation to use the data available from Energy Information Administration (EIA). Most of the commercial forecast providers use the EIA data as the source for their adjustments.

5.2 Oil Price Forecast

These forecasts are available from EIA. It is this consultant's recommendation to use the data available from Energy Information Administration (EIA). Most of the commercial forecast providers use the EIA data as the source for their adjustments.

5.3 Coal Price Forecast

These forecasts are available from EIA. It is this consultant's recommendation to use the data available from Energy Information Administration (EIA). Most of the commercial forecast providers use the EIA data as the source for their adjustments.

6. Electricity Modeling System

As it has been emphasized in the previous sections of this report, the objective of this study is to assess the existing commercial models that can identify the national interest transmission bottlenecks and assess the conditions and actions in elimination of these bottlenecks. This assessment will require the price of electricity and the general economic and national impacts of the elimination of the bottleneck. Consequently as part of Electricity Modeling System a price forecast model that includes the representation of market conditions and behavior, and physical flow models is required. This Electricity Modeling System also needs to include a subsystem to assess the bottlenecks and physical flows. This section is providing the results of this assessment regarding price forecast systems in the presence of (systems that identify and assess) bottleneck(s). The price forecast is conducted with the actual elimination (and verification of elimination) of the bottleneck(s).

Electricity prices are strongly related to physical characteristics of the power system such as loads, hydrological conditions, fuel prices, unit operating characteristics, emission allowances, and transmission capability. Electricity has its distinct characteristics as it cannot be stored economically and transmission congestion may prevent free exchange among control areas. Thus, electricity price shows the greatest volatility among various commodities, and if we simply utilize available methods used for forecasting prices of other commodities, we ought to expect low accuracy.

6.1 Electricity Price Forecast Categories

In this report we categorize price forecasting according to the duration of time, the point of forecasting, and the type of customers.

The following is a description of this categorization:

- Price Forecasting Based on Duration of Time

  This category is similar to load forecasting, which includes long-term load forecasting, medium-term load forecasting and short-term load forecasting. This category includes Long-term Price Forecasting (LTPF) and Short-term Price Forecasting (STPF). LTPF is usually used for planning, such as determining the future sites of generators or transmission lines. STPF is mainly used in the spot market to determine GENCOs' bidding strategies.

- Price Forecasting Based on Point of Forecasting

  In this category, there are Marginal Clearing Price (MCP) Forecasting, Locational Marginal Price (LMP) Forecasting and Zonal Marginal Clearing Price (ZMCP) Forecasting, for the entire system, for a specific bus and for a specific zone, respectively.

- Price Forecasting Based on Type of Customers

The ISO and GENCOs are the two main market participants. They have different goals for price forecasting. In this sense, this category includes ISO Price Forecasting and GENCO Price Forecasting.

Based on general requirements identified in previous sections one of the major needs for the analysis of a bottleneck is to identify economic impacts of elimination of bottlenecks. This can be achieved by a set of tools, assessed in this section, that identify the price of electricity in any specific location. The term of the assessment (up to twenty years), and need for prices in the transmission (wholesale level) lead us to require categories one and two of price forecasting as defined above.

6.2 Electricity Modeling Systems Algorithmic Methodologies

The algorithmic methodologies for the viable Electricity Modeling Systems tools or services available today can be categorized as follows:

- Simulation based
- Neural network based
- Modular time series analysis with heuristic logic

6.2.1 Simulation Based Methods

The simulation-based methods for electricity modeling systems are the most accurate although very complex to implement.

Usually, a simulation component is used which provides the competitive electricity market model that simulates both the behavior of the market participants and the physical structure of the electric system in a regional energy market. It carries out the simulation in two steps:

- Electricity Market Simulation
- Real Time Dispatch and Optimal AC Power Flow

The prices of electricity vary over a wide range due to many factors, such as an unexpected increase in daily loads, generator outages, and transmission congestion or emission constraints. These uncertainties adversely impact market prices. The price volatility also influences the revenue earned by the generators (and consequently their behavior), which serve the imbalance market during any time period. Furthermore, if a generator is unable to deliver its output due to constraints, then it has to fulfill its contract obligation by purchasing energy in the spot market. Therefore, an accurate simulation of the potential generator profitability requires a thorough analysis of the spot price volatility. The volatility model is to allow systematic evaluation of volatility and uncertainty associated with factors such as fuel prices, hydrological conditions, electricity demand, generator and transmission outages, new entrants to the market and any other critical variables which impact the electricity prices.

Electricity prices are significantly influenced by the structure of the electricity market as it evolves over time. In a truly competitive environment, marketers will offer new products; new participants will find it attractive to participate in the market, and thus new financial instruments will become available for risk management. In the presence of liquidity and price discovery, the arbitrage between various energy products and their derivatives will be eliminated over time and equilibrium prices will be established. Determination of the evolving market structure, as inefficient plants are placed on stand-by or shut down and new players enter the market, is essential for forecasting the long-term prices of various energy products. For example, the incorporation of new entrants under tightening emission constraints poses an analytical challenge that requires the comprehensive capabilities of the price forecast tool.

Finally, the near-term performance of the spot market and the medium-term volatility of the futures market provide valuable information on the collective market sentiment; they are used in the volatility model tool to further refine the price forecast. The tool is to determine locational spot prices, forward prices, ancillary service prices, options values (volatility), congestion prices (TCC, CMS) and many other indices applied to accurately assess the market in presence and without the bottlenecks. The tool also includes the simulation of the California, PJM, NEPOOL and other U.S. markets.

6.2.1.1 Electricity Market Simulation

The first step in simulating the operation of an electrical system requires committing generation resources across the grid to meet the customer loads. Different suppliers use state-of-the-art algorithms for modeling market generation commitment. In general this commitment of generating units minimizes the customer procurement cost and maximizes the diversified net profit of the generators for all energy and ancillary services. The arbitrage between energy, ancillary services and locational prices are resolved by minimizing the participants' opportunity costs. The available commercial tools support alternative bidding methods such as, multi-part bidding, and self-scheduling and user-defined bids.

The general requirements for an electricity market simulator include the capability to produce following results:

- Nodal spot or locational marginal prices for all of the identified busses
- Buyer and seller market clearing prices for all of the zones
- Ancillary service prices including:
  - Regulation

  - Spinning reserve
  - Non-spinning reserve by designated availability (10 minute, 30 minute, etc.)
  - Replacement reserve
- Prices for emission allowances
- Prices for capacity (ICAP), as specified
- Transmission Capacity Allocation (TCA)

6.2.1.2 Real Time Dispatch and Optimal AC Power Flow

This subsection includes an initial introduction to Power Flow. The recommended methodology in utilization of Optimal Power Flow for this assessment is provided in part two for this section.

6.2.1.2.1 Power Flow

Power Flow (PF) or Load Flow is a software program that displays the currents, voltages, and MW and MVAR loading of power system devices (e.g. lines, transformers, generators, etc.) after an iterative process of solving for node voltages and currents. There are following commonly used techniques for solving a power flow problem:

- Gauss-Siedel (which updates the node voltage one at a time)
- Newton-Raphson (solves a voltage correction for all the nodes and updates them)
- Decoupled Newton-Raphson
- Fast Decoupled Method

The power flow problem consists of a given transmission network where all lines are represented by an equivalent circuit and transformers by an ideal voltage transformer in series with an impedance. Generators and loads represent the boundary conditions of the solution. Generator or load real and reactive power involves products of voltage and current. Mathematically, the load flow requires a solution of a system of simultaneous nonlinear equations. There are two kinds of power flow packages AC and DC. The AC power flow finds the load flow solutions without any linearization and approximation. DC Power flow is a very widely used approximation of AC power flow. DC Power flow is the linearized approximation that converts AC solution into a simple linear circuit analysis problem. These approximations involve voltages, angles across lines, and impedance values. DC solutions are usually used in contingency analysis scenarios where numerous solutions have to be obtained. Although faster, the DC solution might not be proper for obtaining on systems that are very voltage sensitive.

Independent from the solution methodologies regular (non-optimal) power flow is typically used to answer “What If” questions. For example, what will happen to a system if one takes a specific line out. Power system planner and also operation organizations usually utilize the PF program.

Optimal Power Flow is a power flow as described above plus the introduction of an optimization cost function to the set of power flow equations. An Optimal Power Flow (OPF) program determines the settings of the selected control variables to achieve an optimal steady-state operation of a power system. Generally speaking an OPF is used to answer “How To” questions regarding power system operation.

Typically the primary goal of a generic OPF is to minimize the costs of meeting the load demand for a power system while maintaining the security of the system. Other modes of optimization like loss minimization are supported in the OPF packages. The costs associated with the power system may depend on the situation, but in general they can be attributed to the cost of generating power (megawatts) at each generator. From the viewpoint of an OPF, the maintenance of system security requires keeping each device (lines, transformers, units, etc.) in the power system within its desired operation range at steady-state. This will include maximum and minimum outputs for generators, maximum MVA flows on transmission lines and transformers, as well as keeping system bus voltages within specified ranges. It should be noted that the OPF only addresses steady-state operation of the power system. Topics such as transient stability, dynamic stability, and steady-state contingency analysis are not addressed by OPF.

This study does not require the dynamic or transient stability analysis programs. Stability analyses in the transient and dynamic modes are required for planning of the following activities:

- Relay setting for the protection of the existing or proposed transmission line. In this case transient stability and short circuit programs are utilized. These activities are outside the scope of this assessment. The time frames of these studies are usually in the milliseconds time frame.

- Planning studies for the identification of limits for the steady state operation. These studies are conducted using transient stability programs. The results of these studies are usually used inside the power flow programs as input data. This data is required as part of the input data for this assessment.

- Other planning and design studies for the insertion of new lines or expansion of existing assets.

- Voltage stability studies are conducted for identification of the voltage and load limits to prevent voltage collapse in the system. The voltage and load limits are used as input data to this assessment.

The steady state stability analysis utilizes the power flow (regular or optimal) that is recommended by this study. The steady state contingency analysis as a real time tool is not required by this assessment. These packages although utilize a power flow include a contingency screening process that are usually conducted by the operation groups. The results of these analysis as worst contingencies could be utilized as input data or input to bases case creation subsystem of this study's recommended systems.

An optimal power flow program has to solve an optimization problem where the objective function, equality and inequality constraints are non– linear. Many approaches have been presented in the literature over the years to solve the optimal power flow problem. Some of these approaches include:

- Lambda iteration method - Also called the equal incremental cost criterion (EICC) method. This method has its roots in the common method of economic dispatch used since the 1930s. See A. J. Wood and B. F. Wollenberg, *Power Generation Operation and Control*, New York, NY: John Wiley & Sons, Inc., 1996, pp. 39,517.

- Gradient method - See H. W. Dommel and W. F. Tinney, "Optimal Power Flow Solutions," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-87, October 1968, pp. 1866-1876.

- Newton's method - See D. I. Sun, B. Ashley, B. Brewer, A. Hughes and W. F. Tinney, "Optimal Power Flow by Newton Approach," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-103, October 1984, pp. 2864-2880.

- Linear programming method - See O. Alsac, J. Bright, M. Prais and B. Stott, "Further Developments in LP-Based Optimal Power Flow," *IEEE Transactions on Power Systems*, Vol. 5, No. 3, August 1990, pp. 697-711.

- Interior point method - See Y. Wu, A. S. Debs and R. E. Marsten, "Direct Nonlinear Predictor-Corrector Primal-Dual Interior Point Algorithm for Optimal Power Flows," *1993 IEEE Power Industry Computer Applications Conference*, pp. 138-145.

The Linear Programming (LP) approach is most commonly used among today's providers. This technique transforms the non-linear optimization problem into an iterative algorithm that in each iteration solves a linear optimization problem resulting from linearizing both the objective function and constrains. The value of LP approach is mainly the capability to deal with the inequality constraints. The LP approach also works quite well in case of separable objective functions such as the minimization of the total generation costs. However, when a non-separable objective function arises (such as the minimization of the transmission losses), the implementation of the algorithm should be very careful to obtain a solution.

LP approaches are still attractive due to their capability to consider integer variables using mixed linear-integer programming techniques. In addition, the representation of contingencies is much easier in terms of the sensitivities of the power flow equations.

6.2.1.2.2 Real Time Dispatch and Optimal AC Power Flow For this Assessment

For dispatch, the ideal method, which is available by commercial providers, is to use integrated generation and transmission (Security Constrained) dispatch with an optimal AC/DC load flow algorithm and determine real-time operation of generator, load flow, imbalance prices and congestion management costs. The specific steps and data utilization in running this subsystem are as following:

- The detailed load data for power flow base case is automatically built using the load forecasted data and input data that contains the required information (e.g. distribution factors) for individual loads.
- The individual generation and interchange data for the base case is obtained from the Electricity Market Simulation model. The individual generating unit characteristic data like unit limits, ratings, etc. are obtained from the input data. The individual unit status and their initial setting are obtained from Electricity Market simulation model.
- The line, branch, and bus and limits and other system characteristics are obtained from the input data for the creation of base case. It shall be noted that all of this data are information that are gathered and compiled in the input data based on operational characteristics of the power system. This analysis will only need and consider steady state information for line limits, bus voltage limits, etc.
- The possible contingencies are included in the base case development as input data. The contingencies are also information that is obtained from the input data based on previous operational experience in the system.
- After the based case is built the regular power flow (non optimal) is run. This calculates the flows and bus voltages. All of these calculations are done based on limits and constrained on the lines, units, etc.
- The overloads and of lines are identified by the software package.
- The security constrained optimal power flow is run with the supply cost optimization objective to eliminate the overloads. This optimization utilizes all of the limits and constrains that are entered in the input data.
- The locational prices are calculated.

Throughout this report the term Real Time Dispatch and Security Constrained Dispatch are referring to simulation of optimal power flow solution with the security constrained dispatch mode of optimization.

Real-time dispatch guarantees the true sequential nature of incremental changes in demand/supply and their impacts on the formation of prices, revenues, and congestion. The use of these models enables the user of assessing both forward and real time markets. Most Independent System Operators (ISO), RTOs and grid operators use OPF for real time dispatch. The optimum power flow algorithm used in real-time model utilizes security-constraint dispatch at desired level of contingencies. This in turn provides accurate estimates of regional imports, exports and redispatch costs for congestion management. The general requirements for real time dispatch and optimal AC power flow include the capability to produce following results:

- Real-time nodal prices for all buses including congestion
- Transmission load flow of real and reactive power through each transmission line
- Real time re-dispatch and congestion management charges
- Hourly energy, cost and revenue of each generator
- Real time generator operation such as outages, constrained on and off costs and startup shut-down costs
- Regional electricity imports and exports
- The values of FTRs, TCC, and Congestion Rents

6.2.1.3 General Requirements of Simulation Based Methods

As a general characteristic the simulation-based tools in the market include the modeling of following major features:

- Standard Market Design Compliance
- Congestion Management
- Loop Flow
- Price Cap for specific area
- Transmission Additions

- Conservation Plans
- Weather
- Fuel Issues
- Supply side expansion
- Operational Constraints
- Operating Reserve
- Spinning Reserve
- Emission Constraint
- Market Participation
- Purchase and Sale Contracts
- Cost Reconstruction
- Company Model
- Load Model
- Generation Models
- Network Model
- Marginal Cost
- Operating Reserve
- Dispatch
- Dispatch-able Load Management
- Non-dispatch-able Renewable Resources
- Maintenance Scheduling
- Forced Outages

- Hourly Commitment & Dispatch

6.2.2 Neural Network Method

The neural network method is a simple and powerful tool for forecasting. It does not require much data although the results may not be quite as accurate as the full simulation technique. It identifies parameters to fit a predefined mathematical formula based on historical data and uses the models to predict future electricity prices based on given inputs.

This method although requires smaller volumes of input data, cannot be utilized for this study because:

- It cannot satisfy the general requirement of 20 year ahead forecast.
- It has deficiencies with price spikes.
- Even if other problems are resolved there is a lack of historical data for this methodology.
- Does not include any transmission analysis, hence it cannot identify/verify congestion.

There are no specific commercial providers of neural network based electricity modeling systems. This product exists in academic level at this point.

6.2.3 Modular Time Series Analysis

Time-series forecasting is a forecasting method that uses a set of historical values to predict an outcome. These historic values, often referred to as a "time series", are spaced equally over time and can represent anything, in this case the electricity price in specified intervals with specific constraints.

Time-series forecasting assumes that a time series is a combination of a pattern and some random error. The goal is to separate the pattern from the error by understanding the pattern's trend, its long-term increase or decrease, and its seasonality, the change caused by seasonal factors such as fluctuations in use and demand.

Depending on type of utilized model, i.e. Black-Scholes, multi factor, etc., providers increase the accuracy of the output.

The modular time series analysis with heuristic logic algorithms is usually oversimplified and does not provide accurate results. This method similar to neural network based system has the following major drawbacks:

- It cannot satisfy the general requirement of 20 year ahead forecast.
- Even if other problems are resolved there is a lack of historical data for this methodology.

- Does not include any transmission analysis, hence it cannot identify/verify congestion

KEMA Consulting specifically does not recommend the consideration of this algorithm as the available products or services based on this methodology do not provide correct modeling of physical power systems considerations. Financial based electricity modeling systems utilize this methodology. Some the major providers of this methodology include:

- Global Insight's (formerly DRI-WAFA) AREMOS®
- E-ACUMEN

6.2.4 Recommended Methodology

As it has been indicated in the last three subsection the recommended methodology by this study is the simulations based technique. The following are the major explicit rationales for the this recommendations:

- It can satisfy the general requirements of 20 year ahead forecast.
- It can simulate and capture price under all conditions including spikes
- No historical data is needed.
- Does include detailed transmission analysis, and can identify/verify congestion
- The simulation methodology is the only way that can provide necessary data for the assessment of the physical flows of electricity over paths in response to the combined effects of all other flows on the system.
- This technique can accurately simulate the trade activities within sub-regions.
- The simulation method can provide results for reliability cost/benefits analysis.
- This technique can represent situations with transmission addition to reduce congestion that lead to only small changes in generation costs, but the mere presence of additional transmission capacity creates contestability in each of the local markets that will curb potential market power and reduce prices to consumers.
- This method is the only one that can specifically produce:
  - Real time re-dispatch and congestion management charges
  - Hourly energy, cost and revenue of each generator
  - Real time generator operation such as outages, constrained on and off costs and startup shut-down costs
  - Regional electricity imports and exports
  - The values of FTRs, TCC, and Congestion Rents
- The simulation based methodology usually has accurate results if the following factors are considered in their utilization:
  - The modeling of the components and processes are realistic. This study has provided an overview of the major requirements for component modeling and also general methodology. These information and methodologies are provided based on the field

experiences with organizations like ISOs, RTOs, Generation Companies, Transmission Companies and vendors of providing packages. The recommended methodology is realistic because it is based on components that are available as commercial tools and are utilized by numerous users. Further detailing of components modeling and requirements during possible implementation can increase the assurance of this factor.

- The accuracy of the results of the simulation-based techniques usually largely depends on the accuracy and availability of the input data. This issue is emphasized across this report and required actions and considerations for improving data accuracy are provided.

6.3 Common Characteristics and Requirements of Simulation Based Algorithms

The common characteristics and requirements among simulation-based electricity model algorithms are presented in the following list although the degree and intensity of these issues differ for every methodology:

- Data dependency
- Modeling accuracy

6.3.1 Data Dependency

For obtaining accurate results, accurate and complete input data for the utilized software tool is very critical. Usually the data necessary for these studies contain the following:

- Individual characteristic data of all of the individual generators in the studied area. This includes fuel data, incremental heat rate curves, emissions data, ramp rates, limits, etc.
- Individual characteristic data of all of the major loads in the studied area.
- Individual transmission line characteristic data, which is used in power, flow studies.
- Historical data for energy and ancillary prices, loads, load flows, outages, reserves, etc., for the study area.
- Data modeling issues and constraints related to the study areas and regulatory rules.

Gathering this data (if it is available without conflict of interest) is a very time and resource-consuming task. This task will require tens of work-years of effort. After the initial data gathering activity is complete, the maintenance and update of it will be an on-going process and require thousands of work-hours effort every year. The details of work power requirements are presented in section 6.5 of this report.

6.3.2 Modeling Accuracy

Good and dependable electricity market modeling packages in the market generally include in the algorithmic calculations or constraints:

- Generation Uncertainty
- Load Uncertainty
- Fluctuations in Hydroelectricity Production

- Fluctuations in Fuel Prices
- Elasticity of demand and supply to price
- Dispatchable DSM
- Generation Outages
- Transmission Outages
- Transmission Congestion
- Multi Market Transmission Dispatch
- Market Participants' Behavior (based on anticipated prices)
- Gaming and Market Manipulation (market power, counter party risk)
- Duration of Operation and Forecast (hour of the day, day of the week, month, year)
- Bidding Strategies and Market Liquidity
- Limits on generating unit bids
- GENCO's generating unit limits
- Generation minimum up/down times
- Generation ramp rate limits
- Fuel constraints
- Crew constraints
- System emission allowance
- Zonal emission allowance
- Global Warming allowance

The above list summarizes some of the detailed modeling requirements for the recommended system. Disregarding the type of the Unit Commitment that is utilized in the model (i.e. linear programming, Lagrange Relaxation, or Economic Merit Ordering base) the following features and capabilities (that are available from most of the products in the market) are recommended:

- Arbitrage
- Trading Position Model (long, short, option commodity)
- Purchase/Sale Market Structure
- Emission
- Fuel Constraint
- Risk
- Data Interface

The important constraints that are available and supported by most of available products in the market include:

- System Load
- Reserve
- Net Interchange
- Must Run
- Must Off
- Min Up/Down
- Initial Status
- Crew Constraints
- Multi Hour Start up
- Separate Unit Start-Up Fuel
- $/MBTU
- Piecewise Linear IHR Curve
- Unit Hourly MW Capacity, High & Low Dispatch Limits, Max Spinning Reserve Limit
- Ramp Rate

The consideration and modeling of the above constrains are recommended by this study as part of the detailed requirements of Electricity Modeling System.

6.3.3 Practical Considerations in Modeling

The following is a list of practical considerations in the simulation modeling.

1. **Generation Expansion Uncertainties**

   Different providers have alternative ways of modeling new generation modeling in their model. One of these modeling techniques is probabilistic approach to modeling new generation supply. In this approach the proposed plants are generically classified by status (i.e. under construction, advanced development or early development). As part of data construction probabilities are developed for the likelihood of different projects moving forward. These probabilities are based on status, region, and technology. Also individual probabilities are assigned to some developers. The ultimate outcome in this approach is a distribution of the yearly-expected capacity additions that is included in the data model.

2. **Fuel Constraints**

   Many utilities have fuel supply constraints that affect the commitment of units. The fuel constraints usually include lower and upper limits on the amount of a given fuel used by a unit during the study period. Adding fuel constraints complicates the resource-scheduling problem severely. A fuel constraint limits the amounts of fuel available to a single-fuel unit and may change the schedule commitment of this unit. For example, if a unit is committed at all times then adding fuel constraints to limit the available amount of fuel would decrease the generation and number of on-line hours of the unit. If we think in terms of priority order, the ranking of the fuel-constrained unit will decrease. Similarly, consider a unit that uses multiple types of fuel and the cheapest fuel is constrained while other fuels are unlimited. Then it is clear that this unit should be dispatched based on the cost of the more expensive, unlimited fuel if the expensive fuel is used at the optimum solution. If, however, only the limited fuel is used at the optimum, then this unit should be dispatched based on the cost of the limited fuel.

   There are two approaches to include fuel constraints in the resource-scheduling problem: the decoupled approach and the integrated approach. The decoupled approach is based on decomposing the problem into a unit commitment problem, and a fuel dispatch problem that is very weakly coupled. This decoupling method may solve fuel dispatch problems that are very general involving multiple sources of fuel, each of which can supply multiple units. However, decoupling the fuel dispatch from the unit commitment can lead to commitments that are far from the optimal solution that can be obtained if fuel constraints were considered in unit commitment. Therefore, we recommend the second approach, which incorporates fuel constraints inside the unit commitment model. However, it should be stated that the integrated approach is limited as to the types and numbers of fuel constraints that it can consider efficiently although it can be expected to give commitments that are much closer to the optimum solution than the decoupled approach.

3. Bilateral Contracts

A bilateral contract allows customers to negotiate directly with sellers in terms of delivery and price. Customers could be wholesale, retail customers, or aggregators representing a group of customers. The sellers could be generators, marketers or brokers.

GENCOs could generate their own power to supply bilateral contracts if their marginal price is lower than the market price at certain hours. Otherwise, they would purchase energy from the market to supply bilateral contracts if the market prices are lower than their marginal prices.

Bilateral contracts modeling as explained in this section is available from some of the vendors.

4. Ramping Considerations

Since the ramp rate constraints affect individual generating units, they are modeled in most of the tools in the market.

Due to ramping constraints, the status of a unit within one hour may possess several possible states. The construction of the state space considers the minimum up/down times and ramping constraints.

5. Implementation of Maintenance Schedule

Due to schedule maintenance some units may not be available (must off) or their output must be reduced for certain hours during the study period. On the other hand, other units must be ON (must run) during some periods or during the whole study time. These cases may be considered by adjusting the cost of the states.

6. Global Warming and Emission Constraints

Generation scheduling shall consider global warming and two primary power plants emissions, SO2 and NOx. The modeling of global warming and emissions would depend on the heat rate characteristics of the individual generating unit. Therefore, as the output of a thermal unit increases the resultant global warming and emissions increase and vice versa. Since, in unit commitment, the maximum generation capability of a unit is determined, we accordingly would find its corresponding emission. If the sum of unit emissions were within the prescribed limits for emission and global warming, then the states of the units would satisfy the emission constraints. Otherwise, if the proposed emissions exceed the desired limits, then the corresponding schedule will be adjusted.

Global warming and emission constraints are coupling constraints in the sense that they couple all time periods together.

7. Bus Model Utilization

This assessment is considered a planning study. Planning studies usually utilize bus-oriented models. Bus oriented planning models (rather than node and breaker oriented models) are to be used for construction of the power system network model for the recommended tools. The node-oriented models are utilized for operational tools and assessments. The maintenance and handling of bus-oriented models are less tedious than node oriented models.

8. Dispatchable DSM

Price-Responsive Demand (PRD) or price-responsive load (PRL) programs are emerging on the electricity marketplace. The modeling of these programs as part of the selected tool is critical in producing practical and accurate results. One example of these programs is called the Day-Ahead Demand Response Program (DADRP). This program allows industrial, commercial, and aggregations of residential customers to offer demand reduction bids into day-ahead electricity market to help reduce system demand and receive market prices for any load reduction. Another example program is called the Emergency Demand Response Program (EDRP). The primary goal of this program is to bolster reserves during times of system emergency. Many believe these types of PRD programs will bring additional "discipline" to electricity markets. The simulation of these programs is not available by most of the vendors at this time (because they are evolving). The capability to include these requirements as they evolve is recommended.

6.4 Providers and Products

The recommended methodology for Electricity Modeling System consists requires the following two subsystems:

- Electricity Market Simulation
- Real Time Dispatch and Optimal AC Power Flow

The Electricity Market Simulation systems have become very important since the start of restructuring in the North American Electricity Market. Extensive use of this product has emerged especially by asset managers and optimizers of merchant generation companies. These entities have been using these systems for valuation and profit analysis proposes. The ISOs and RTOs also use these products in their planning and market rule establishment activities. The maturity of these products extends to last eight years. However the algorithms used inside these packages have been around for decades. These algorithms were used in production planning tools. This product is still evolving.

The Optimal Power Flow has always been one of the key drivers of electric utilities' planning activities. Utility planners have implemented these packages based on very mature software products from external providers. The commercial OPF packages have a maturity of twenty-five years. The algorithms used in today's commercial packages are mostly based on methodologies and techniques that have been used before the start of restructuring. Two new major components of these packages include the modules for Locational Marginal Pricing and Available Transmission Capacity. These modules have about ten years of maturity.

In selection and screening of the vendors only the ones with record in providing planning tools were considered. For example, as a power flow provider, ALSTOM ESCA was not considered because their LMP package is used as an on line operational tool.

Potential providers of Electricity Modeling Systems that are based on simulation techniques as specified in this report are:

- ABB (GridView, TRACE)
- EPIS (Aurora)
- EPRI (TRACE, CAR)
- GE (MAPS)
- Henwood Energy Systems (PROSYM)

- LCG Group (UPLAN)
- Nexant (SCOPE)
- PowerWorld (Simulator)
- PTI
- Siemens/NewEnergy

It shall be noted that these vendors and products are the ones that have broad industry clients and are considered field proven. Many other companies provide this modeling for the desired functionality and time frame of this assessment as services. This assessment did not investigate those providers. The scope of this study is to assess available tools and products.

6.4.1 ABB

ABB provides multiple products that can be utilized for this assessment. TRACE is an optimal power flow based software package for maximum power transfer capability evaluation in the interconnected power system. TRACE calculates both the simultaneous and non-simultaneous power transfer capabilities, which form the basis for the computation of Available Transfer Capability (ATC) postings mandated by FERC. TRACE performs its calculations based on AC power flow modeling and system operation limits. An optional DC power flow model is also available for even faster solutions where voltage problems do not exist. The program consists of two major software modules--one module does efficient contingency selection and the second module is a full AC optimal power flow program. Together, the two modules calculate the multi-area, simultaneous power transfer capabilities subject to thermal, voltage, and interface limits. This package includes very thorough set of manuals. This package is also marketed by EPRI. One of the major applications and use of this program has been the study conducted by EPRI for NERC. The NERC Reliability Authority Working Group (RAWG) created the Pre-Season Security Assessment Study Team (PSAST) to plan and develop the study and to prepare a confidential report to RAWG. This study was conducted for summer of 2002 Eastern Interconnection Pre-Season.

Another product from ABB is called GridView. This product is sold as a package and it also used by ABB's internal consultants for providing services. GridView has built-up databases for all NERC regions in the US. This product includes detailed modeling of generation, transmission, load and market structure modeling such as generation variable cost, forced outage rates, transmission interfaces and flow gates, hourly load profiles for different load serving entities etc. GridView's methodology combines generation, transmission, loads, fuels, and market economics modeling in one integrated framework to deliver location dependent market indicators (price, etc.), transmission system utilization measures and market performance indices. GridView uses a security constrained unit commitment and economic dispatch. This product also includes an optimal power flow. The package includes a market scenario module that can be used for simulation of different situations in the system.

6.4.1.1 Major Strengths and Shortcomings of GridView

The some of the other major strengths of this package include:

- Locational marginal clearing price. This feature is required for price forecast data required by this assessment.
- Network congestion analysis. This feature is needed for reliability analysis and bottleneck identification.
- Generation performance analysis. This feature can enhance the ultimate assessment. The generation performance has an impact on final price of electricity.

- Market simulation. This subsystem is a requirement for this assessment.

This product's major shortcoming is the use and customer base of it. This product is not used as commonly as other products especially among large users like ISOs.

6.4.2 EPIS (Aurora)

Aurora is the name of the product from EPIS. This is a comprehensive detailed Wholesale Price Forecast (Electricity Market Simulation) package with strong uncertainty analysis capability. The algorithm of this package divides the whole United States to 66 market areas. The database structure for these areas is flexible enough to be subdivided or merged together. This product is capable of hourly chronological simulation for:

- Multi-Area, Transmission Constrained Dispatch
- Hourly, Economically Optimized Unit Commitment
- Fundamental or Non-fundamental Based Pricing

The general algorithm of this product can be summarized as following:

- AURORA builds a resource stack for each area.
- The marginal unit is found for each area given the native demand.
- Given transmission costs, losses and constraints, economic power flows are determined. This is done with considering equivalent pipelines between areas rather than actual transmission lines.
- Small sets of the most economic flows are allowed to take place.
- The clearing price is found for each area given native load and imports and exports.
- Using genetic algorithm techniques considers the potential benefits of moving power in markets; steps 3 through 5 are repeated until no significant benefits can be obtained by additional power flows on pipelines.This product specifically utilizes a unit commitment package in the market-modeling module. Some of the major characteristics of this module are:

- Units commit based on the value created over an operating period.
- Using a pre-forecast of prices, economic value is determined based on units' minimum uptime and minimum downtime.
- Iterates to a solution of consistent prices and resource operation
- Committed units run at minimum (or maximum) capacity depending on the value in each hour of operation. This product also has a subsystem for hydro modeling which:

- Optimizes the use of hydro energies.
- Uses hydro constraints--instantaneous maximums and minimums, and sustained peaking maximums.
- Within shaping constraints, shapes hydro to flatten load. Accounts for regional hydro imports and exports.This product can provide uncertainty using Monte Carlo or Latin Hypercube treatment of price drivers:

- Demand, fuel prices, thermal outage, & hydro generation
- Built in sampling distributions, or user defined
- Flexible period definition for stochastic variables
- Correlated variable specification

This product's Proprietary algorithm is faster than competitors for equivalent detail. The benchmark conducted by vendor shows full 8760-hour pricing run for all of the Midwest and Eastern US/Canada in less than 12 minutes (>5050 units, 20 areas). The provider claims that annual pricing runs using a quality hour sample set in under two minutes. This performance has been witnessed in clients that conducted long term (20 years or more) economically optimized capacity expansion studies.

6.4.2.1 Major Strengths and Shortcomings of Aurora

Some of the major strengths of this product include:

- Detailed generation modeling. This feature will produce more realistic results in price forecasting. Some of these details include:
    - Startup costs, minimum up/down time for unit commitment.
    - Multiple capacity segments and heat rates.
    - Peaking operation for Single Cycle segment of Combined Cycle units.
    - Unit ramp rates.
    - Primary and secondary fuel options with fuel limits.
- Flexible emissions definition and pricing. Generation scheduling considers the effects of power plants emissions, e.g. SO_2 and NO_x. The modeling of emissions depends on the heat rate characteristics of the individual generating unit. As the output of a thermal unit increases the

resultant emissions increase and vice versa. The emission consideration and pricing is critical for obtaining realistic price of electricity.

- Consideration for bidding factors, and shadow bidding specification. The bidding process has an impact on the final electricity prices. This feature improves the accuracy of the price forecast.

- Good performance. The performance of the selected package can be important since it impacts the required time and effort for each cases study. These assessments will be conducted on continuous basis. Even a small improvement of performance can translate to thousands of dollars.Modeling of hydro system. The modeling of hydro system from this provider is quite detailed. This feature can be important for the cases that involve major hydro assets and analysis of ancillary services. Hydro units are actively used for regulation of frequency. The major

weaknesses of this product are as following:

- The way that transmissions between areas are modeled (pipelines). The first issue with this kind of modeling is the lack of detailed reliability and congestion assessment for internal to the area assessment situations. This method also prevents realistic satisfaction of requirement for bottlenecks identification between areas. The real and physical modeling and analysis of actual transmission lines are required to product results expected by the assessment.

- The division of the whole system to multi areas that might prevent realistic inter-area market simulation. The assessment tool needs to be flexible to consider any desired area or sub-area for the analysts. This can be a major area of enhancement if this product is selected for the study. One way of overcoming this problem could be to encourage this provider in partnering with a power flow provider. Lack of a power flow. This subsystem is needed for determination of real-time operation of generator, load flow, imbalance prices and congestion management costs. It is also the subsystem that identifies the congestion. Not having an optimal power flow blocks the assessment of congestion and bottlenecks and also nodal price forecast. The security constrained OPF package is required to provide nodal-pricing solution and the value of FTRs (Firm Transmission Rights). Aurora provides the zonal prices. This provider is in the process of partnering with GE (GE MAPS) to overcome this shortcoming.

6.4.3 EPRI

EPRI has been marketing a power flow based software package for maximum power transfer capability evaluation in the interconnected power system. This product is called TRACE (Transfer Capability Evaluation) program. TRACE is also marketed by ABB. TRACE calculates both the simultaneous and non-simultaneous power transfer capabilities, which form the basis for the computation of Available Transfer Capability (ATC) postings mandated by FERC. TRACE performs fast calculations based on accurate AC power flow modeling and realistic system operation limits. An optional DC power flow model is also available for even faster solutions where voltage problems do not exist. The program consists of two major software modules--one module does efficient contingency selection and the second module is a full AC optimal power flow program. Together, the two modules calculate the multi-area, simultaneous power transfer capabilities subject to thermal, voltage, and interface limits. This package includes very thorough set of manuals. One of the major applications and use of this program has been the study conducted by EPRI for NERC. The NERC Reliability Authority Working Group (RAWG) created the Pre-Season Security Assessment Study Team (PSAST) to plan and develop the study and to prepare a confidential report to RAWG. This study was conducted for summer of 2002 Eastern Interconnection Pre-Season.

Another program provided by EPRI is called Community Activity Room (CAR). This is a newly developed analytical and visualization software technology mainly for power trading. Community Activity Room (CAR) uses the metaphor of a many-sided room to show the ranges of operation within which market activities can freely take place. CAR graphics define the limits of the power market, locating congested bottlenecks and suggesting the combinations of net import and net export from various control areas that will avoid congestion. This product is not as field proven as other products. However the user interface capabilities of CAR are very unique. CAR as a product, although directly does not target the major requirements of this assessment, can improve the use-ability of any selected system, if it is integrated as part of the whole package. By implementing a system like this the job of analysts in conducting the final assessments will be easier. Rather than looking into tabular displays they can utilize this graphical tool. CAR has the potential to display market prices in the same way as congestion is displayed. This will require further development.

The strengths and weaknesses of this vendor is no going to be discussed since it is not addressing the direct needs of this assessment.

6.4.4 GE MAPS

GE Power Systems provides a product that is called Multi-Area Production Simulation (MAPS) program. MAPS is a model that calculates hour-by-hour production costs while recognizing the constraints on the dispatch of generation imposed by the transmission system. Using simulation techniques like Monte Carlo based on trends from production costs the Locational Marginal Prices (only) are forecasted. GE provides another product called GE MARS, which is widely used for reliability studies. GE MAPS is more applicable for this assessment's requirements.

MAPS uses a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved ac load flow, to calculate the real power flows for each generation dispatch. This enables the user to capture the economic penalties of redispatching the generation to satisfy transmission line flow limits and security constraints.

Separate dispatches of the interconnected system and the individual companies' own load and generation are performed to determine the economic interchange of energy between companies. Several methods of cost reconstruction are available to compute the individual company costs in the total system environment. The chronological nature of the hourly loads is modeled for all hours in the year. In the electrical representation, the loads are modeled by individual bus. In addition to the traditional production costing results, MAPS can provide information on the hourly spot prices at individual buses and on the flows on selected transmission lines for all hours in the year, as well as identifying the companies responsible for the flows on a given line.

Maps can be utilized to achieve the following:

- Transmission Access – MAPS calculates the hour spot price ($/MWh) at each bus modeled.

- Loop Flow or Uncompensated Wheeling – The detailed transmission modeling and cost reconstruction algorithms in MAPS combine to identify the companies contributing to the flow on a given transmission line and to define the production cost impact of that loading.

- Transmission Bottlenecks – MAPS can determine which transmission lines and interfaces in the system are bottlenecks and how many hours during the year these lines are limiting. Next, the program can be used to assess, from an economic point of view, the feasibility of various methods, such as transmission line upgrades or the installation of phase-angle regulators for alleviating bottlenecks.

- Evaluation of New Generation, Transmission, or Demand-Side Facilities – MAPS can evaluate which of the available alternatives under consideration has the most favorable impact on system operation in terms of production costs and transmission system loading.

MAPS models the system chronologically on an hourly basis, dispatching the generation to serve the load for all hours in a year.

The following are the characteristics that can be modeled in GE MAPS:

- Generation, the following detailed features are supported:
  - Multi-pass unit commitment.
  - Each unit can have up to seven loading segments,
  - Toping and blend fuel,
  - Fixed O&M in $/kW/year and variable O&M in $/MWh and $/fired hour,
  - A separate bidding adder in $/MWh can also be input for each unit. This cost is added to the costs used to determine the commitment and dispatch order of the units, but is ignored when computing actual unit costs.
  - Start-up costs as a function of the number of hours that the unit has been off-line.
  - In the unit commitment process, MAPS models the minimum downtime and uptime on thermal units.
  - Units can also be identified as must-run with the user specifying that the entire unit is must-run, or only the minimum portion, with the remainder of the unit committed on an economic basis as needed.
  - Spinning reserve requirements for every unit,
  - Hydro and pumped hydro
  - Full and partial forced outage
  - Maintenance can be specified on a daily basis for any number of maintenance periods during the year.
  - The thermal generating units bid into the system at their costs, based on fuel prices, O&M and emission costs, bid adders, and heat rates. Alternatively, the user can input the bid price in $/MWh by unit. This price will then be used in the commitment and dispatch to determine the way in which the units operate.
  - Jointly owned generating units (thermal, pondage, and energy storage)

- Nearly all unit characteristics including rating.
- Maintenance scheduling
- Forced outages (Monte Carlo or recursive)

- Dispatch-able load management and non-dispatch able renewable - MAPS can model types of dispatch-able DSM and load control as thermal generating units with the appropriate characteristics and costs. Load management strategies such as batteries or thermal energy storage can be modeled as energy-storage devices. MAPS models non-dispatch able DSM and load control and renewables such as photovoltaic or wind energy as hourly modifications to the load.

- Operational constraints - The production simulation is formulated as a linear programming (LP) OPF problem where the objective function is to minimize the production costs subject to electrical and business constraints. MAPS models each security constraint as a single constraint in the LP formulation. MAPS derives these constraints from the production costing input data (for example, identified must-run units and minimum down-time for generation units) and from user-specified operating nomograms, such as those often used by system operators to represent voltage and transient stability limits. MAPS monitors the flows on individual transmission lines and interfaces on an hourly basis to ensure that the line or interface limits, or other security constraints such as import limits, are not violated while dispatching the generation system. MAPS can also consider other user-specified contingencies such as the tripping of lines or groups of lines, or the tripping of load or generation at specified buses.

- Emissions - MAPS models two general types of emissions. The first type of emission is a function of the amount of fuel being used. This type would typically be used to model sulfur and particulate emission. The second type of emission is a function of the unit operation, but is not directly related to the amount of fuel. This type could be used to model NOx emissions, which can decrease with increased power output.

- Representation of various power market participants - Through the assignment of loads and generation, the various participants in the power market can be represented in MAPS.

- Transmission Network- MAPS contains two distinct models for representing the transmission system. The original approach uses a transportation model to limit the transfer between interconnected areas during the dispatch of the system generation. The second approach performs a transmission-constrained production simulation, using a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved ac load flow, to calculate the real power flows for each generation dispatch. This makes it possible to capture the economic penalties of redispatching the generation to satisfy transmission line flow limits and security constraints. In the electrical representation, all physical components of the transmission system are modeled, including transmission lines, phase-angle regulators, and HVDC lines.

This product has been in the market for more than twenty years. It has a very large customer base (hundreds of licenses). The benchmark of this product has shown capacity of working well with very large number of buses in the network, i.e. 40,000 plus.

The price forecast in this package is based on trend calculated from cost.

6.4.4.1 Major Strengths and Shortcomings of MAPS

Major strengths of MAPS include:

- Detailed and comprehensive modeling of market, transmission, and generation. This kind of modeling is very good for satisfying the reliability and congestion assessment requirement. The major examples of these detailed modeling include:
    - Two distinct models for representing the transmission system.
    - Representation of market participants.
    - Generation modeling.
    - Load management modeling.
    - Emission modeling.
- Field proven power flow. Power system planners have used this product for decades. This improves the efficiency of activities involved in data preparation and debugging. The time of analysts especially during non-convergence situations is not spend in finding problems with software modeling. It is rather used in capturing the model errors.

The major weakness of this product is too much detail in modeling which requires tremendous amount of data. The data gathering, preparation, and maintenance effort is a major part of conducting this assessment. The details although create more accuracy can create more work for analysts involved in the assessment.

6.4.5 Henwood MARKETSYM & PROSYM

MARKETSYM™, is a decision tool in analyzing power markets and supports functions such as generation unit analysis, fuel planning, market price forecasting, and generation/portfolio valuation. MARKETSYM's analytical engine is called PROSYM™. PROSYM is the chronological electric power production costing simulation computer software package that is produces by Henwood. It is designed for performing planning and operational studies, and as a result of its chronological nature, accommodates detailed hour-by-hour investigation of the operations of electric utilities. Because of its ability to handle detailed information in a chronological fashion, planning studies performed with PROSYM may reflect actual electric utility operations. The major characteristics of this model are as follows:

- Simulates a year, hour-by-hour, in one week increments
- Major input data into the model are fuel costs, variable operation and maintenance costs, and startup costs.
- Meets hourly loads In the most economic manner possible, given a specified set of generating resources
- Recognizes operating constraints imposed on individual units
- Output is production costs by resource to meet weekly loads
- Output is available by regions, by plants, and by plant types
- Includes a pollution emission subroutine which estimates emissions with each scenario
- The unit commitment module, as a general matter utilizes a sophisticated economic merit ordering that stacks the units with lower operating costs with higher priority. This process goes through an iterative process such that the total cost of operating the system is minimized.
- The unit commitment module recognizes generator operating constraints such as minimum down time and maximum ramp rates, hydro, etc.
- The PROSYM model considers the whole electric industry as divided into a number of interlinked transmission areas, which correspond to the utilities' transmission capabilities and geographic boundaries as individual transmission areas. The constraints for transmission constraints between each of the individual "transmission areas" in the study region are respected. PROSYM does not have a power flow of its own. Recently (April 2002), due to partnership with Power World transmission modeling functionality is supported that, as an integrated package, is not very field proven yet. This newly integrated package (two products together) will address the transmission modeling needs of this assessment.

6.4.5.1 Major Strengths and Shortcomings of PROSYM

Major Strengths of this product include:

- Field proven market simulation since it is in use by more than 150 user companies. This improves the efficiency of activities involved in data preparation and debugging. The time of analysts especially during debugging situations is not spent in finding problems with software modeling. It is rather used in capturing the model errors.
- Consideration for important production planning related issues enables the user to conduct studies for this assessments required period. This also provides detailed functionalities of generation, and load.
- This vendor is an excellent source of data, especially in hard to obtain areas like generation unit data (unit emission, etc.) for the areas of study and modeling required by this assessment. This data can cut the time and effort of search and preparation of modeling details.

The major shortcomings of this product include:

- Not having an optimal power flow for assessment of congestion and bottlenecks and also nodal price forecast. The fact that this provider has a partnership with a provider of this function can overcome this problem, if it is provided. The security constrained OPF (with FTR calculation feature) package is required to provide nodal-pricing solution and the value of FTRs (Firm Transmission Rights). PROSYM provides the zonal prices.
- Data model is complex to build. But the required data is usually available from this vendor.

6.4.6 LCG Group (UPLAN)

The name of the product is UPLAN Network Power Model (UPLAN-NPM). This is a Multi-commodity, Multi-area Optimal Power Flow (MMOPF) that also contains a market simulation model. The MMOPF model simulates electricity trades and maximizes the profits from the trades, taking into account network constraints, operating characteristics of plants and transmission congestion. The system simulates the energy and ancillary markets as well as the participants' trading behavior. It establishes internally consistent forward prices for all market segments, and uses the resources selected in the forward market in an optimal power flow algorithm to determine the hourly real-time prices and unit operation.

UPLAN Network Power Model is a competitive electricity market model that simulates both the behavior of the market participants and the physical structure of the electric system in a regional energy market. It carries out the simulation in the following two steps.

Step 1. Electricity Market Simulation: This model simulates the forward energy and ancillary services markets, including regulation, spinning reserves, non-spinning reserves and replacement or capacity reserves. The model simulates participants' behavior using either user-specified bidding strategies or bids internally developed in the program, based on rational bidding. The model recognizes that different segments of the interconnected region may have different market protocols. The electricity market model contains an auction or bidding model that allows users to develop competitive bidding strategies and evaluate the impacts on the participants. It is possible for a generator in a competitive market to bid its short-run marginal cost (MC), but this runs the risk that the market price will be insufficient to recover long-run total costs. But, by bidding much higher than the MC, the generator runs the risk of losing market share. Since the short-run electricity demand and supply are relatively inelastic, low market prices may force some generators to be retired, creating shortages, which in turn drives up future prices. UPLAN can adjust the bids so that the resulting prices are sufficient for the market to be economically viable. In the long run, however, if prices go up, new players will be attracted to the market, and the added generation will drive prices down until it ceases to be profitable to make new additions. To determine the forward prices, the electricity market model in UPLAN optimizes the returns from all the trades by taking into consideration all the resource constraints. To meet the short-term economic viability requirements, bidders may choose the option of adjusting the bids over a period of time by an amount over the bidders' marginal cost, as allowed by supply and demand elasticity in the simulated markets. The economic viability criteria may produce ideal prices under competitive bidding.

Step 2. The Real-time Dispatch Model. The real time dispatch is conducted using an optimal power flow. The optimal power flow model of the UPLAN system is used for simulating the real-time prices in the competitive power markets. The electricity market simulation model selects resources available to meet the anticipated demand plus necessary ancillary services more efficiently and determines the forward or ex ante Market Clearing Prices (MCP). Then, the real-time dispatch model, an Optimal AC Power Flow (OPF) model, simulates the actual system dispatch and determines the real and reactive power flow in each hour. Any energy imbalances, voltage quality or congestion problems are mitigated by the OPF re-dispatch algorithm. Thus, the electricity prices determined by the real-time simulation may be different from the forward prices, due to several reasons cited below:

- Some scheduled generators may not be available due to forced outages.
- Loads may be higher/lower due to forecasting errors.
- Transmission may not be possible due to congestion.
- Additional generation may be necessary for voltage support, outages, or congestion management, etc.

This package also contains the following two subsystems as separate modules:

- The Volatility Model based on Monte Carlo Simulation for scenario analysis.
- The Merchant Plant Model for assessment of new entrants and their impact on future prices. The Merchant Plant Addition (MPA) model uses a non-linear decomposition algorithm to perform the following tasks:
  - It searches the transmission network to determine those nodes where the revenues from the projected market prices can support new entrants. Out of the resulting selected set of nodes, some are used as potential sites for locating new capacity additions.
  - The MPA retires those units that are not economically viable, after testing whether refurbishment intended to improve total efficiency or achieve desired emission characteristics leads to a viable unit.
  - The MPA model determines the optimal timing and capacity of new entrants that meet specified investment criteria in terms of rate of return and financial risk.
  - The volatility analysis simulates boom and bust situations for new entrants, to illuminate the effects of uncertainty on key market drivers, and to analyze their impacts on the price.

The model determines locational spot prices, forward prices, ancillary service prices, options values (volatility), congestion prices (TCC, CMS) and many other indices applied to accurately assess the market and evaluate buy/sell and hedging strategies.

In 1989, UPLAN was adapted to simulate daily competitive market behavior in the UK electricity grid, in order to plan the privatized electrical industry in the United Kingdom (UK). In 1991, UPLAN was used to model a competition-based national pool for Iberdrola, S.A., the largest utility in Spain. Over the last decade in the United States, UPLAN has been applied to simulate the restructured, multi-area power market in the reliability regions within North America. UPLAN has also been used internationally to evaluate deregulation alternatives for countries in Europe, Asia, Australia and Africa. UPLAN has been extensively tested in more than 100 prior studies and regulatory filings involving competitive market analysis and integrated resource planning. Some of the recent applications and users of UPLAN include:

- AMOCO Power Resources, Houston, Texas;
- California Energy Commission, Sacramento, California;
- California ISO, Folsom, California;
- CINERGY Corporation, Cincinnati, Ohio.
- Duke Solutions, Raleigh, North Carolina;
- Energy Pacific, San Diego, California;
- ENOVA Energy, San Diego, California;
- ENRON Capital & Trade, San Francisco, California;
- Florida Power & Light, Juno Beach, Florida;
- FMC Corporation, Pocatello, Idaho;
- GWF Power, Walnut Greek, California;
- NEO Corporation, Minneapolis, Minnesota;
- Oxbow Power Corporation, West Palm Beach, Florida;
- Sacramento Municipal Utility District, Sacramento, California; and
- Southern California Edison, Rosemead, California

- Theodore Barry and Associates, Los Angeles, California

6.4.6.1 Major Strengths and Shortcomings of UPLAN

The major strengths of this product include:

- Thorough modeling of all market and transmission details. This vendor has a history of providing both Electricity Market Simulation, and Real Time Dispatch and Optimal AC Power Flow. The Electricity Market Simulation is important in scheduling generation and finding zonal prices and modeling market participants' behavior. The security constrained OPF (with FTR calculation feature) package is required to provide nodal-pricing solution and the value of FTRs (Firm Transmission Rights).

- Big customer base. This vendor has been used (specially as a service provider) in many regulatory ruling and analysis cases. The big customer base makes the product more field proven, which improves the reliability and usability of the product.

- Good and detailed modeling of details like new generation modeling, hydro modeling, etc. This vendor also provides the required data for different areas (especially four different modeling areas considered by this study). This data can cut the time and effort of search and preparation of modeling details.

The major shortcomings of this product are:

- Its dependency on large database. This provider is also a data provider. This shortcoming can be corrected if the user decides to use the data provided by this vendor. Performance issues. This vendor does not install this product in customer site as often as they use it for consulting services. The performance for the one time service studies are not considered as critical as if they were used on a continuous basis by the provider.

6.4.7 Nexant

This provider has a very extensive power flow package that has been used broadly for reliability studies in the power industry. However no viable market simulation or price forecast is available at this point.

Two of the power flow products are called SCOPE, and Hedge. SCOPE is a package for analyzing electric power system network operation. The power flow engine of this provider is very well established as the worlds most used OPF in energy management systems. It can be used in all phases of power system network engineering, from deregulated energy markets and real-time control, to long-range planning. SCOPE includes power flow, network topology processor, contingency analysis, switching control, and security constrained OPF (SCOPF). It uses an AC or a DC (MW-only) network model. SCOPE's multiple functions include:

- Economic cost or price-based dispatch in modern mixed spot and bilateral markets,
- Comprehensive nodal and zonal locational marginal pricing,
- Remedial control action,
- MW transfer maximization,
- Loss minimization,
- Reactive power ancillary service bidding, and
- Capacitor installation (sizing and placement).

Hedge is a product mostly used for FTR and TCC options analysis. Hedge is based on the same power flow technology as SCOPE and has special optimization function for TCC and FTR calculation.

The power flow algorithm of this product is based on Newton-Raphson. The optimization engine utilizes the Linear Programming techniques. These programs utilize the input loads for single hourly periods.

This product is in continuous use by 100s of EMS systems users around the globe. This product is also used by numerous users for planning studies. Most recently CA ISO, and PJM have utilized Hedge for FTR and TCC (congestion analysis) calculations. NY ISO uses SCOPE for LMP calculations.

6.4.7.1 Major Strengths and Shortcomings of SCOPE

This provider is a power flow provider for many Energy Management System vendors. Some of the major strengths of this product include:

- Field proven power flow algorithm. Besides improved the results, this improves the efficiency of activities involved in data preparation and debugging. The time of analysts especially during non-convergence situations is not spend in finding problems with software modeling. It is rather used in capturing the model errors.

- This vendor has a history of proven both Real Time Dispatch and Optimal Power Flow. The security constrained OPF (with FTR calculation feature) package is required to provide nodal-pricing solution and the value of FTRs (Firm Transmission Rights). The OPF package of this vendor can be used to address reliability, LMP, and FTR needs of this study.

Major shortcoming of this product is the lack of Electricity Market Simulation Package.

6.4.8 PowerWorld (Simulator)

Simulator is the power flow package of PowerWorld Corporation. This product includes a regular and optimal power flow. PowerWorld is sized to be able of solving systems of up to 60,000 buses. Simulator supports detailed modeling of almost all of power system components (e.g. DC lines, Capacitors, etc.). This product is based on a very user-friendly user interface and database manager. Simulator's (input) data base format is compatible with PTI, and GE PSLF formats (specific versions). The one-line diagrams in the format of other providers (PTI) are supported. The user interface features of this product are very advanced; it includes features like animation of line and tieline flows, etc. These features make the process of obtaining and implementation of input data and also one-line diagrams very simple and can save the users enormous amount of labor time depending on the size of the model data. This product's generation dispatch includes a typical abbreviated (not as detailed as a typical on line economic dispatch packages that are more detailed and customized) economic dispatch for generators inside the study area that the detailed cost information for units are available. For other areas two options of area and distributed slack bus are supported.

This products Optimal Power Flow supports calculation of bus locational marginal prices. It also supports the security constrained dispatch mode of optimization, which is critical for economically dispatching a system while taking into account transmission system congestion. Simulator's OPF supports loss minimization.

The regular power flow can be based on Newton Raphson, Gauss-Siedel, and DC power flow. The OPF algorithm is base on Linear Programming technique.

Simulator provides a number of tools for calculating sensitivities. For example, it can compute and display power transfer distribution factors (PTDFs). Simulator also calculates line flow and interface sensitivities. Simulator provides access to the system admittance matrix and power flow Jacobian, and they can be exported into your other analysis tools. This is useful for debugging situations.

This product is also licensed and is being used by hundreds of users around the world. Some major consulting companies use this product for conducting their reliability studies.

Simulator also features contingency analysis tools that implements a full AC power flow for each contingency.

6.4.8.1 Strengths and Shortcomings of Simulator

The major strengths of this product include:

- Inclusion of all of the modes and forms of power flow (AC, DC, OPF, etc.). This is very useful especially for the initial model building and base case development activities. Different types of

PF can create alternative ways of verification of modeling issues and resolving non-convergent cases.

- Very user-friendly user interface. This feature is very important because it can expedite the study analysis and solution verification among other tasks of analysts.
- The security constrained OPF (with FTR calculation feature) package. This software is required to provide nodal-pricing solution and the value of FTRs (Firm Transmission Rights).

The major shortcoming of this product is lack of market simulation. However this can be overcome by considering the market simulation partner of this vendor Henwood.

6.4.9 PTI

This provider has extensive array of power flow base packages that has been used broadly for reliability studies in the power industry for more than twenty-five years. The power flow based products of this provider are used by more than 600 organizations globally.

The products from this provider that may be utilized by this study include:

- PSS/E **(**Power System Simulator for Engineering) is a program for simulating, analyzing, and optimizing power system performance. It uses Newton-Raphson (AC and DC) technique for regular power flow and Linear Programming for optimization in performing power flow studies, unbalanced fault analysis, and dynamic simulation available to the user.

- TPLAN, a transmission reliability assessment package for planners, operators, owners, and users of transmission systems, provides quick comprehensive setups to perform n-1, n-1-1, n-2, and/or n-3, evaluations. Transition to probabilistic assessment methods from the viewpoints of transmission owners and providers or customers is also supported. TPLAN provides specific answers to how to questions. This product uses same power flow engines as of PSSE.

- MUST **(**Managing and Utilizing System Transmission) efficiently calculates the impact of transactions on key network elements, identifies the most limiting contingencies and constraints, calculates FCITC transfer capability, and the sensitivity of FCITC to transactions and generation dispatch changes. MUST calculates transmission transfer capabilities in grids the size of the U.S. Eastern Interconnection in very short times (low seconds), and displays the impact of transactions and generation dispatch variations on transfer capabilities.

In addition to classical optimization modes these products can be utilized for:

- Transfer capability investigation
- Location-based marginal cost assessment
- Ancillary service opportunity cost assessment
- Impact assessment base case development

Market simulation or price forecast is not available at this point. The company is in the process of developing a new product called LMPSIM that will provide forecasts of LMP prices.

6.4.9.1 Strengths and Shortcomings of Products

Some of the general strengths of these providers' products include:

- Transient and "long-term" capability. The long-term requirements of this assessment are satisfy-able by these packages. These packages have been used by planning groups of utility companies for decades. Besides improved the results, this improves the efficiency of activities involved in data preparation and debugging. The time of analysts especially during non-convergence situations is not spend in finding problems with software modeling. It is rather used in capturing the model errors.

- Capability to create specialized graphics, forms and tabular reports. This is useful for facilitating the analysis process.

- One-line diagram view. Network models can be created from the one-line diagrams. The one-line diagrams are supported by almost all of the power flow providers. The capability to create one-lines from network model is very useful. The alternative, i.e. manual creation of one-line diagrams can be quite time consuming. Building of every one-line diagram can take up to one work day if built manually.

The major shortcoming of this product is lack of market simulation.

6.4.10 Siemens/ New Energy

There are two products provided by this provider. The Power CC product has less field application for decision support and planning activities. Power CC has been utilized more in real time and near real time studies. The more relevant product is called PROMOD IV. This product is well known for its simulation capability of Locational Marginal Pricing (LMP) forecasting.

PROMOD IV results offer detailed market and asset data for use in price forecasting for decision support. PROMOD IV models the dynamics of the electricity market by determining the effects of transmission congestions, fuel costs, generator availability, bidding behavior, and load growth on market prices.

This product performs an 8760-hourly generation commitment and dispatch simulation recognizing both generation and transmission impacts at the bus level. The PROMOD IV simulation incorporates full transmission modeling and a security-constrained unit commitment and dispatch, with Monte Carlo modeling of generator unit random outages. PROMOD IV forecasts hourly energy prices, unit generation, revenues and fuel consumption, nodal bus and zonal energy market prices, external market transactions, transmission flows, and Congestion Revenue Rights (CRR). The methodology mimics the LMP markets operational in PJM and NY ISO today.

Some of the major features of this function include:

- Locational Marginal Price calculation.
- Congestion analysis module.
- Equipment outage scheduling and simulation.
- Simulation of newly build generators in the future.
- Transmission Rights price calculation.

Some the major clients that use this product or services based on this product include:

- Oglethorpe Power Corporation
- Midwest Cooperative G&T
- Florida Independent Power Producer
- Southwest Cooperative G&T
- Western Utility

- Midwest Utility
- Southwestern Utility
- Large Southwestern Utility
- Northeastern Utility
- Entergy
- Eastern Utility
- Central & Southwest Services
- Central Louisiana Electric Company
- A Midwestern Power Marketer
- An Independent Power Producer
- PJM Load-Serving Entity
- PECO Energy
- Atlantic Energy

6.4.10.1 Strengths and Shortcomings of PROMOD IV

Some of the major strengths of this product include:

- Identification and assessment of transmission congestion. This feature is a requirement by this study.
- Capability to analyze strategies to alleviate the cost and uncertainty of transmission, including valuing both Congestion Revenue Rights (CRR) and various sale and purchase contract structures under a multitude of scenarios. This improves the flexibility of the tool and also can be a factor in improving the results.
- Can evaluate the profitability of generating units and the influence of associated market volatility under various bidding strategies, commitment elections (self scheduling or full market participation). This feature can be used for the scenarios that especially involve generation addition scenarios.

- Can simulate generator and transmission outage scheduling options. The analysis of outage of power system assets is one of the areas that the analysts would want to assess. This feature will be beneficial for conducting cases involving these outages.

- Simulates generator additions and network topology changes as well as many other parameters. The inclusion of this feature addresses the requirement of simulating future new plant additions in the area of study.

- Can simulate, market operations with associated interconnected systems modeled in either aggregate or full detail, and identify (as input) key market drivers and risks such as fuel prices, demand levels, and new merchant plant entrants. The flexibility to simulate in both detailed and aggregate mode improves the productivity of the assessment team and provides the option to look at overview picture first and focus in details if needed.

- Capable to conduct efficient detailed transmission studies (AC power flow analysis) on a multitude of select hours representing various distributions of demand and generation throughout of the buses on the grid resulting from the security constrained commitment and dispatch simulation. This is a requirement for this assessment.

- Can decompose LMP’s to identify and evaluate the contributing and economically constraining elements and their associated loss component on the grid.

- Can develop and assess reliable and profitable dispatch strategies. This improves the reliability results.

- The MAINPLAN maintenance optimization module is specifically designed to quantify unit maintenance outages. The optimized maintenance schedules can be used in PROMOD IV to facilitate assessments of the combined volumetric and market risk under multi-regional conditions.

Although this provider has all of the required packages by this study it does not have a very strong presence as a standalone product provider. This product is not used as a stand-alone delivered system as it is used for service providers as a consulting service.

6.4.11 Comparison Tables of Providers

Table 6.4.1 provides an overview comparison of the above products. The major functional requirements as identified in previous sections are shown in this table. This table provides availability of major functionalities by recommended vendors. "N" represents not supported. "Y" represents supported even if not fully.

Table 6.4.1

Provider	Product	Electricity Market Simulation					Real Time Dispatch and Optimal AC Power Flow				
		Nodal Price	Emission Price	Zonal Price	Ancillary Price	TCA	Nodal Price	Load Flow		OPF	Congestion & Dispatch
								AC	DC		
ABB	TRACE	Does not provide this subsystem				Y	Y	Y	Y	Y	Y
	GridView	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
EPIS	AURORA	Y	Y	Y	Y	Y	N**	N**	N**	N**	N**
EPRI	TRACE	Does not provide this subsystem					Y	Y	Y	Y	Y
	CAR	Does not provide this subsystem					-				
GE	MAPS	Y	Y	N	N	Y	Y	Y	Y	Y	Y
Henwood	PROSYM	Y	Y	Y	Y	Y	Y*	Y*	Y*	Y*	Y*
LCG	UPLAN	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y
NEXANT	SCOPE	Does not provide this subsystem					Y	Y	Y	Y	Y
PowerWorld	Simulator	Does not provide this subsystem					Y	Y	Y	Y	Y
PTI	PSS/E	Does not provide this subsystem					Y	Y	Y	Y	Y
	TPLAN	Does not provide this subsystem					Y	Y	Y	Y	Y
	MUST	Does not provide this subsystem					Y	Y	Y	Y	Y
Siemens	PROMOD VI	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y

* Supported by partnership with other providers. Only the lines between areas of study are considered. Inter-area study is not provided.

** Area study is considered. No power flow. The connections between areas are modeled as pipelines.

Table 6.4.2 provides some additional characteristics of these products.

Table 6.4.2

Provider	Product	Time Domain	Load Profile	Number of Supported Buses*	Modeling of Transmission Level Voltage (down to 69 kv)
ABB	TRACE	Single Hour	Single Hour	40,000	Yes
	GridView	Annual Hourly	Annual Hourly	40,000	Yes
EPIS	AURORA	Annual Hourly	Annual Hourly	-	No
EPRI	TRACE	Single Hour	Annual Hourly	40,000	Yes
	CAR	Single Hour	-	-	No
GE	MAPS	Annual Hourly	Annual Hourly	30,000	Yes
Henwood	PROSYM	Annual Hourly	Annual Hourly	60,000 through PowerWorld	Yes through PowerWorld
LCG	UPLAN	Annual Hourly	Annual Hourly	Unlimited	Yes
NEXANT	SCOPE	Single Hour	Single Hour	40,000	Yes
PowerWorld	Simulator	Single Hour	Peak Shoulder Interpolation	60,000	Yes
PTI	PSS/E	Annual Hourly & Single Hour	Annual Hourly	Unlimited	Yes
	TPLAN				Yes
	MUST				Yes
Siemens	PROMOD VI	Annual Hourly	Annual Hourly	40,000	Yes

* this number is also limited by hardware capabilities of the platform

Table 6.4.3 provides a summary of applications of these products.

Table 6.4.3 Summary of Applications of Products

Provider	Product	Users	Comments
ABB	TRACE	EPRI	Pre-Season Security Assessment Study Team
	GridView	Unknown	Unknown
EPIS	AURORA	Numerous generation and marketing and trading companies	It has been used for price forecast and asset valuation.
EPRI	TRACE	Self	Pre-Season Security Assessment Study Team
GE	MAPS	Numerous Transmission Companies	Transmission Planning
		PJM	Reserve Requirements Studies, Generator Unit Un-Availability Studies
		NY ISO	Generation Expansion Studies
		ISO NE	Reliability Studies
		MISO	Transmission Expansion and Reliability Studies
Henwood	PROSYM	Numerous Generation and Marketing and Trading Companies	Price Forecast, Asset Valuation
LCG	UPLAN	Numerous Generation and Marketing and Trading Companies	Price Forecast, Asset Valuation
		Regulatory Agencies	Litigation
NEXANT	SCOPE	Transmission and Generation Companies	LMP Calculations
PowerWorld	Simulator	Generation and Transmission Companies	LMP Calculations
PTI	PSS/E, MUST	ISO NE	Reliability Studies
		NY ISO	Reliability Studies
		Numerous Transmission Companies	Transmission Planning and interconnection studies
Siemens	PROMOD VI	Some Generation and Marketing and Trading Companies	Price Forecast, Asset Valuation

Table 6.4.4 provides a summary of model applications to objectives.

Table 6.4.4 Summary of Model Applications to Objectives

Product	Policy Level Analysis Y= Yes, N=No	Assessment of Current Bottlenecks N= National, R= Regional & ISO, S= State	Bottleneck Assessment Based on Physical Limitation Y= Yes, N=No	Bottleneck Assessment as a Result of Changing Market Dynamics Y= Yes, N=No	Forecast of Bottlenecks for next 10= 10 Years, 20=20Years
TRACE	**N**	**N, R, S**	**Y**	**N**	**10, 20**
GridView	**Y**	**N, R, S**	**Y**	**Y**	**10, 20**
AURORA	**N**	**At this point is only Pipeline based for regions.**	**N**	**Y**	**10, 20 if used with one of the capable power flows**
TRACE	**N**	**N, R, S**	**Y**	**N**	**10, 20**
CAR	-	-	-	-	-
MAPS	**Y**	**N, R, S**	**Y**	**N**	**10, 20**
PROSYM	**Y** If with PowerWorld	**N, R, S**	**Y if implemented with PowerWorld**	**Y**	**10, 20 If used with PowerWorld**
UPLAN	**Y**	**N, R, S**	**Y**	**Y**	**10, 20**
SCOPE **Simulator**	**N**	**N, R, S**	**Y**	**N**	**10, 20**
PSS/E, MUST	**Y**	**N, R, S**	**Y**	**N**	**10, 20**
PROMOD VI	**Y**	**N, R, S**	**Y**	**Y**	**10, 20**

6.5 Purchase and Ownership Costs

The initial costs include the purchase and implementation expenses of load forecast function. The details of these costs are presented in table 6.5.1. This initial implementation is estimated to require one calendar year. The prices and hours accuracy is ±15 percent.

Table 6.5.1

Item	Labor Cost in Working Hours	Approximate Price of Software in $
Electricity Modeling System, including, license, integration, customization, etc.	-	1,500,000
Hardware	-	200,000
Specification and detailed requirement definition	1000	200,000
Project management	2000	400,000
Data preparation	5000	1000,000
Testing	1000	200,000
Total	9000	3,500,000

The ownership cost is the cost of maintaining and operating of the software. This cost is on per year basis. Another option for owner ship of systems like these is to purchase them based on annual license. The price range for site license of a Real Time Dispatch and Optimal AC Power Flow package is between $40,000 to $50,000 per year. The price range for site license of an Electricity Market Simulation package is between $150,000 to $300,000 per year.

Section 3.0 of this report presented the initial modeling assumption for this assessment. According to that assumption the whole country is divided to the following study regions:

- Eastern Interconnection. The northeastern region contains more mature market modeling characteristics. Modeling of markets like PJM, NY ISO, and ISO NE is quite complex from modeling data point of view. This study assumes a separate model for Midwest region because the electricity market is in the evolving trend in this region. As the Midwest market matures, additional data and alterations to existing data will be required. To minimize the impact of these changes, the Midwest region is modeled separately. This report assumes that the Northeast and Southeast regions can be modeled together for ease of modeling maintenance activities. The capability of handling large number of buses by available products supports this assumption.

- Midwest Interconnection
- Western Interconnection
- Southern (or ERCOT) Interconnection

Based on these modeling divisions we suggest four different separate (hardware and software) systems for conducting assessments of these areas. This study assumes four engineers for preparation, maintenance, application of modeling data for the above areas area. Majority of these people are resources who can maintain the model and run the programs (data requirements are addressed in next section). The initial installation and debugging of the model for each area typically takes about six months. Some of the major responsibilities of these engineers include:

- Running of the system for assigned assessments
- Debugging of data problems and modeling inaccuracies
- Coordination of the activities and database contents with other subsystems, installs, and upgrades.

The computer software packages i.e. Power Flow and Market Simulation functions and database maintenance software will require four full time software engineers. Some of the major responsibilities of these engineers include:

- Installation of software and data files.
- Installation of software upgrades and patches
- Ensuring that the system operates (runs) during working or software running times.
- Support and problem shooting for the four users of the system.
- Participation in initial and on going data installation and upgrades
- Participation in debugging processes

For software maintenance and upgrade one can purchase an annual maintenance package.

7. Database and Modeling Challenges in the Utilization of the Tools

The Electricity Modeling System results and simulation inputs can be derived from the loads, fuel prices, generator and transmission databases, and can be based on the current information developed from a variety of sources. Information on the operating characteristics of the generating units needs to be developed from the provided data.

Providers of services for Electricity Modeling System simulation have in most cases developed relational databases of generating plants, loads and transmission lines for the existing electric utility resources for each of the North American Electric Reliability Council (NERC) regions. The major source for these databases are the Energy Information Administration (EIA) of the United States Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC) and various NERC reports. Some of the price forecast service providers offer the data (in their own format) for nominal price.

Based on the region that the considered assets are located in, the study area data is applied. For example, if the study area is located in the Midwest, the NERC regions that are included in full or part are MAPP, SPP, ENTERGY, MAIN, ECAR and SERC. As an example we consider geographic region of the Midwest Interconnect. The Midwest Interconnect system represents a complex regional market with a large number of investor-owned and municipal utilities (including rural co-ops). The entire region has a very strong transmission network that fosters a significant interaction of operations and interchange of energy between the various control areas within the NERC regions in the Midwest Interconnect. Figure 2 illustrates the huge amount of transmission data that needs to be prepared and entered. Other required data and information include:

- Demand peak and energy requirements
- Supply systems data
- Fuel prices
- Emissions data
- Option values

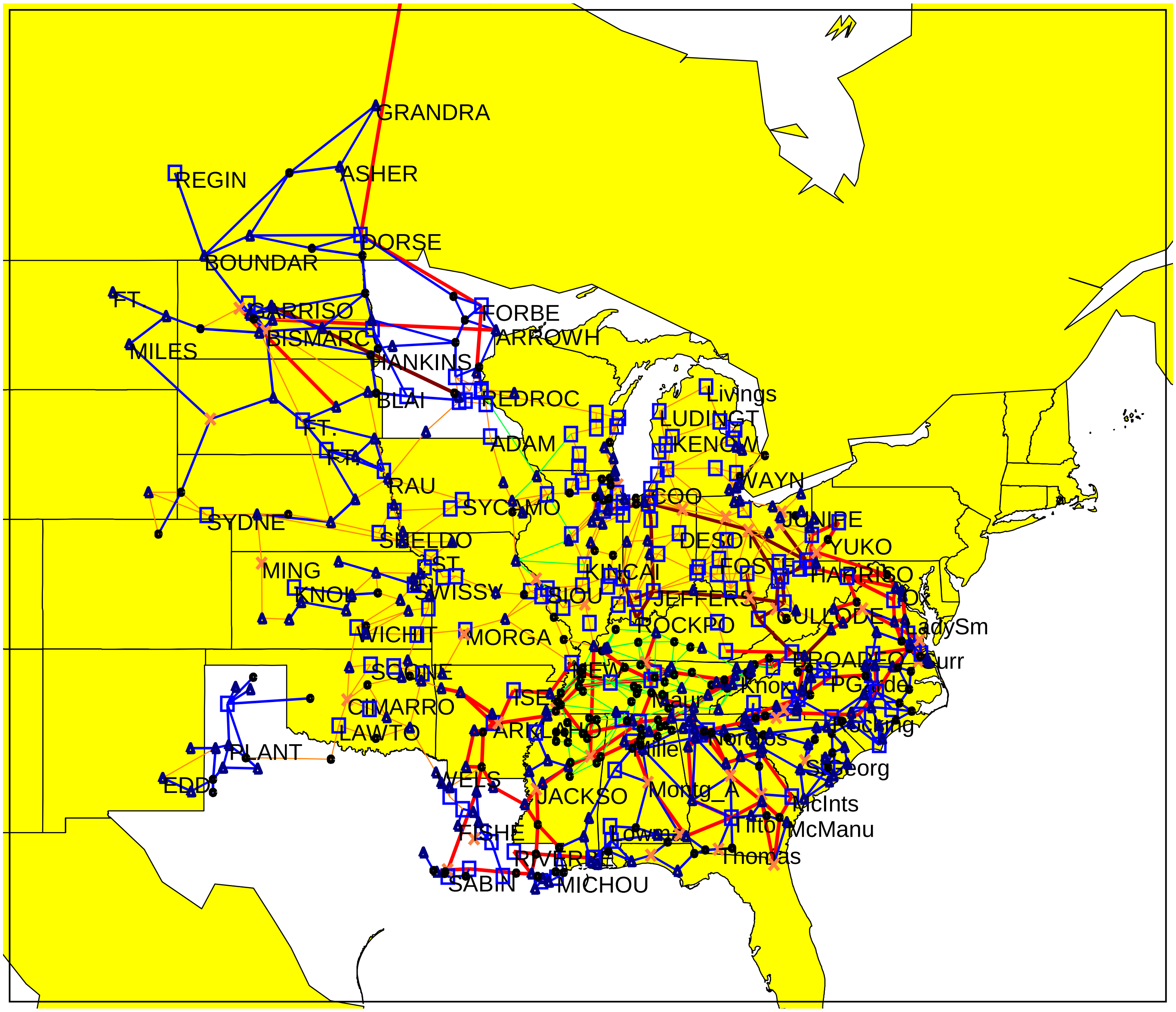


Figure 2. Midwest Interconnect Transmission Network

References:
1. Federal Energy Regulatory Commission Forms 1 and 2 and 714 and 715.
2. Coordinating Councils: MAPP, SPP, MAIN, and SERC - 1997 Loads and Resources Reports, OE-411.
3. Energy Information Administration (1997) Form EIA 412.

The gathered data for every area includes all of the grid reliability criteria at several levels, such as NERC, regional reliability councils, ISO, control area, and local level. For example the line limits that will be entered and utilized by the programs will be based on reliability criteria of these entities. The changes to these criteria can be entered and managed by the assigned personnel via the modeling management tools.

The preparation and maintenance of this data (if available due to conflicts of interest) will require a tremendous amount of work. The required effort for this data preparation activity has produced the following challenges for in-house software tools, especially simulation methodology based tools:

- Cost justification for the tens of working years required for data preparation
- Availability schedule for the required data
- Conflict of interest and legal issues related to data ownership

This study suggests the consideration of the following sources of data, solutions and tools for building and maintaining this database:

- Most of the transmission and generation data are available and kept up to date with existing ISOs and RTOs.
- For the generation data utilize the data available from these sources.
- For transmission data use the data from these sources but utilize the tool explained in the following section. The process of using the tool is also explained in the following section.

The recommended tool provides a sophisticated model capable of performing large-scale system optimizations for a regional electricity market. Due to the extensive features of the model and the size of its databases, it may seem to be a daunting task to try to grasp the model in its entirety.

To facilitate the task of accessing, editing, and understanding the bulk of the underlying data, the vendors have built an interface (tabular or graphical), referred to as the “data input and maintenance tool”. This front-end module usually provides intuitive means to access and revise all generation, load and transmission data at any level of detail. It also provides a means for the dynamic evaluation of the energy market by allowing changes to the underlying market database and providing quick detection and elimination of erroneous data. This tool is usually included in Electricity Modeling System (or its subsystems) packages.

The preparation of the data for the selected tool requires thorough knowledge and experience of power systems modeling and database building. <u>The process of building data model includes the following critical tasks:</u>

- Decision making, on the control areas and voltage levels to be considered.
- Decision on the total number of buses
- Decision on selection of the source of data.
- Establishment of a process to make the modeling of the systems useable for the future studies.

Examples of voltage levels and lines that are typically included in the model are:

- DC Lines
- 765 kv
- 500 kv
- 345 kv

The generating units that are typically included in the model are:

- Gas
- Oil
- Coal
- Hydro
- Nuclear
- Pumped storage
- Synchronous condenser

The data calibration and tuning regarding electricity modeling system is an ongoing process. Some of the major issues and activities regarding this process include:

- Verification and tuning for generator cost or price curves.
- Verification and tuning of all of the generator parameters like ramp rates.
- Verification/calibration of parameters that impact the solutions with regard to practices of the region.

- Verification/calibration of scheduling versus impact modeling, netting rules. Relationship between firm and non-firm calculations.

- Development/calibration and verification of load flow model for calculations. This includes, line impedance data, bus and line limits (voltage, MVA, etc.), generator limits, optimization limits, etc. This activity can be extremely tedious with large number of buses involved in this study. In this set of activities the validity of the power flow solution has to be verified. If there are any invalid solutions the impacting parameters in the vicinity of the identified inaccuracy have to be studied and adjusted until the problem is resolved and the correct solution is obtained. Examples of invalid solution include negative or very unrealistic bus voltage solutions, divergence in specific buses, etc.

- Load flow case (s) creation

- Verification of naming conventions

- Verifications and adjustments to obtain Load flow solution options.

- Development/calibrations of the seasonal models for long-term.

- Verification and calibration of Outage scheduling data and rules This includes generator, load and transmission outages.

- Verification and development of area interchange control and generation block dispatch including pump storage and hydro.

- Verification and tuning of Modeling of transactions

- Verification and tuning of point to point bilateral self-scheduling and general area interchange control

- Tuning of modeling of area load changes in the load flow case including conforming and non-conforming load.

- Development/calibration and verification of rules and data needs for modeling external control areas. Adjacent and remote control areas.

7.1 Network Reduction and Equivalencing Tools

Network reduction and equivalencing tools provide a means of obtaining small, manageable, and accurate equivalents from extremely large network systems. These tools enable the user to determine how much of the internal and external system has to be modeled and what external data is needed. Internal system is the area of the interest for the study. Equally, they allow the unnecessary parts of the internal system (e.g., at low voltages) to be identified and eliminated. One of the issues that need to be addressed as part of the implementation of these systems is to identify the minimum level of the voltage that will be modeled in the internal model. The models usually enable the users to obtain accurate, small, well-conditioned reduced power flow models. These tools automate the most time consuming parts of the process of designing, validating, and routinely updating such models. The following are some of the major characteristics of the desired network reduction system:

- The tool limits the total amount of "external" data needed.
- This tool determines how accurate individual items or blocks of external data need to be.
- It forms equivalents that minimize the size of the reduced model.
- It ensures that the reduction is valid for variations in system loading and topology.
- It automatically verifies the accuracy of the final reduced equivalent to avoid models with unrealistic, ill-conditioned, state-dependent impedances.

The results of the tool build the data in the industry acceptable standards. The most viable vendors for this tool are:

- Power Technologies Inc., PSS/E
- Nexant, the product is called Model X.

The network reduction packages were considered <u>very critical</u> during the times that computer and software capabilities were limiting the number of buses that could be modeled in a power system network. Since the advancement of the computer and calculating technologies the issue of network reduction has become some how less critical. The argument is that with all of the new advancements the providers of power system analysis packages have been able to show that networks with the size of 35,000 to 40,000 buses can be solved without any issues. This study does not claim that the network reduction is an absolute must as part of the proposed data preparation. The information regarding network reduction is provided to show the scope of work and the alternatives that can be considered. As part of the decisions regarding the network size, voltage levels, etc. one may consider the utilization of a network reduction package if appropriate.

The following are some of the consideration in using or bypassing network reduction:

- The process of model maintenance becomes more complex by the use of network reduction. Every major change needs to be applied to original network and carried over to the reduced network.
- Some times the effort of applying network reduction is not creating any benefit. This happens especially in the cases that the number of buses in any study is below 60,000.
- In the case that the size of the system is extraordinarily large e.g. above 60,000 buses the use of network reduction can lessen this size to half and improve the data maintenance processes.
- Network reduction can be used as a tool to implement the modeling rules for the area of interest e.g. enforcement of voltage level not to go below specified level.
- Network reduction can be used for reduction of so called external model.

These issues need to be evaluated in detail if the methodologies suggested by this study are to be implemented.

7.2 Process and Practical Considerations in Building and Maintaining Network Model

The process for building and maintaining network models for this study is presented in the block diagram presented in Figure 3. It shall be noted that the network reduction process is included in considering the discussions provided in the previous section. The initial assumption for this recommendation is ability to conduct the study for separate regions as:

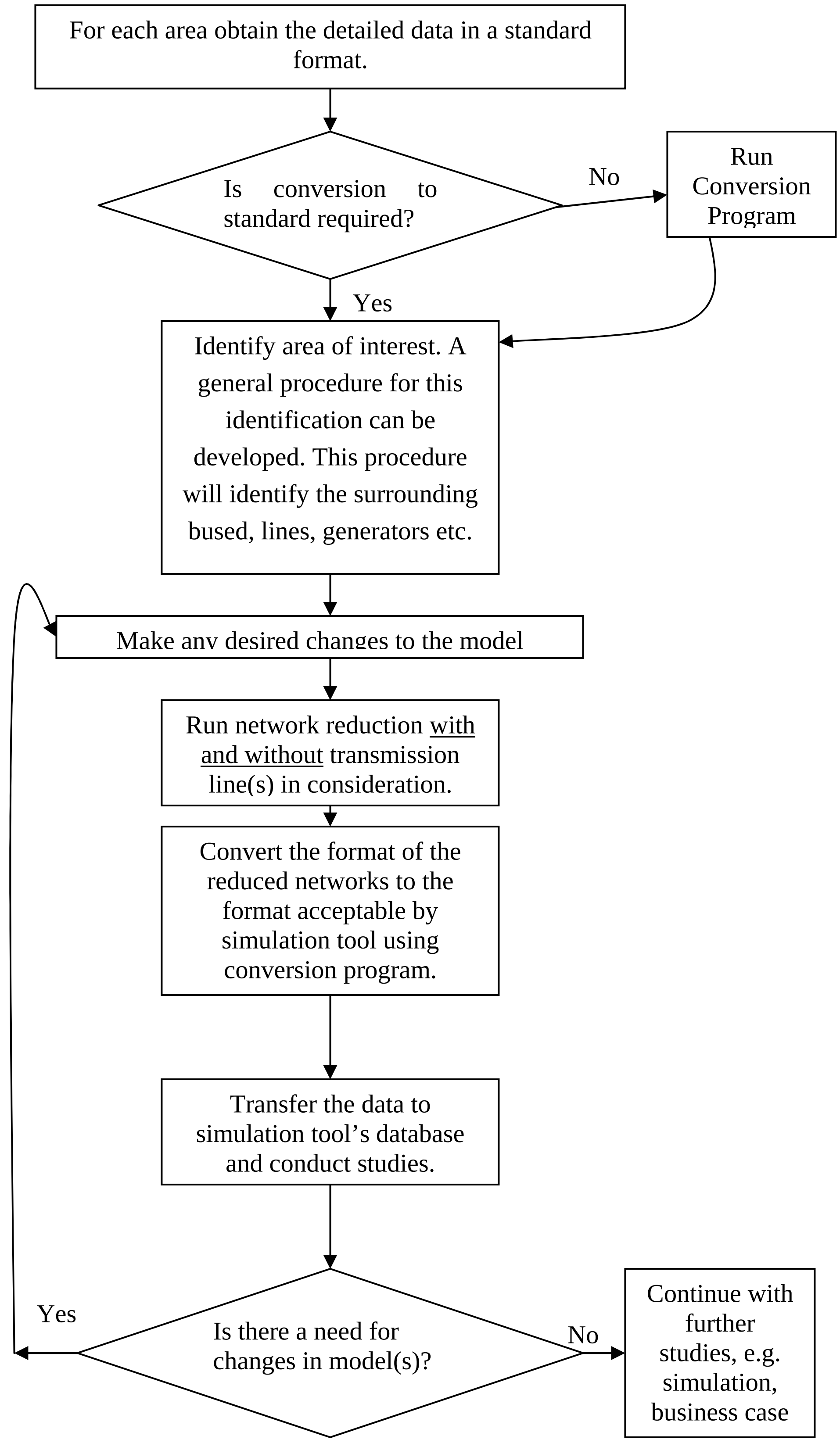
- Eastern Interconnection. The northeastern region contains more mature market modeling characteristics. Modeling of markets like PJM, NY ISO, and ISO NE is quite complex from modeling data point of view. This study assumes a separate model for Midwest region because the electricity market is in the evolving trend in this region. As the Midwest market matures, additional data and alterations to existing data will be required. To minimize the impact of these changes, the Midwest region is modeled separately. This report assumes that the Northeast and Southeast regions can be modeled together for ease of modeling maintenance activities. The capability of handling large number of buses by available products supports this assumption.
- Midwest Interconnection
- Western Interconnection
- Southern (or ERCOT) Interconnection

It is also assumed that the data for each region will be available in some kind of standard format (IEEE, PS/SE, etc.) from one of the following resources:

- Corresponding ISO/RTO
- The regions NERC organization
- EIA
- Data vendors

Purchasing or development of a tool for data conversion shall be included in the plan if the data is not available in a standard format. The vendors of network reduction tools or system simulation tools typically have or can deliver this tool.

Figure 3- The process for building and maintaining network



As presented in Figure 3, if during the simulation the need for addition or delete of major components like transmission lines or etc. arises the changes have to be applied to unreduced network and the whole process of network reduction needs to be repeated.

7.3 Generation Data

The data requirement for market simulation typically includes detailed generation data. This data can be obtained from same sources as network data as described in the previous section. The data equivalencing for generators can be done utilizing the same tools used for network. The generator database includes the following major information:

- Heat rates,
- Full and partial outages,
- Fixed and variable O&M cost,
- Minimum downtime and uptime,
- Must-run capability,
- Fuel type,
- Data on maintenance scheduling,
- Pumped storage,
- External contracts,
- Operating reserves.

7.4 Resource and Product Requirements

The database and system model maintenance will require tremendous amount of labor. Section 3.0 of this report suggested the preparation and maintenance of the data model for each of the following areas:

- Eastern Interconnection. The northeastern region contains more mature market modeling characteristics. Modeling of markets like PJM, NY ISO, and ISO NE is quite complex from modeling data point of view. This study assumes a separate model for Midwest region because the electricity market is in the evolving trend in this region. As the Midwest market matures, additional data and alterations to existing data will be required. To minimize the impact of these changes, the Midwest region is modeled separately. This report assumes that the Northeast and Southeast regions can be modeled together for ease of modeling maintenance activities. The capability of handling large number of buses by available products supports this assumption.
- Midwest Interconnection
- Western Interconnection
- Southern (or ERCOT) Interconnection

For these areas the following resources are required:

- One person for preparation and maintenance of generation model and data.
- One person for preparation and maintenance of transmission data.
- One person for preparation and maintenance of fuel and other forecasted data.
- One person for general model coordination.

Based on above areas of activities the total number of 4 people per year will be required for preparation and maintenance of the model. This number includes the operation and use of network reduction or any other data activities.

8. Monte Carlo Simulation

The final solution from Electricity Modeling system will be price of electricity (local, zonal, energy, ancillary, etc.), and the identified congested paths. These solutions are driven by input variables like price of fuel, load forecast, etc. The actual solution for each value of input variables is only one value. These solutions would have been perfect if one had the following conditions:

- The input variables (e.g. fuel prices) were deterministic.
- There was certain (close to one hundred percent) knowledge that the input variables only change and vary in a very small range.

In real world that is not the situation. One way in reflecting these changes is to conduct thousands of simulation cases for based on changes of input variables in their range. Another way of dealing with this uncertainty is to conduct some kind of simulation based on probability of occurrences of input variables. The most practiced technique for this probability based scenario analysis is Monte Carlo simulation. Other methods like sensitivity analysis can also be used. Currently most of the available commercial products for the Electricity Modeling Systems utilize Monte Carlo simulation. This is because:

- These products are targeted towards electricity traders, marketers, and asset managers who are quite used to Monte Carlo simulation.
- Monte Carlo simulation is usually available as a third party package and the vendors do not have to spend time and financial resources for research and development. While the development and integration of sensitivity techniques require substantial amount of time and financial investment.

Usually the analysis of price volatility is based on the probability distribution for each of a series of key drivers. The users can determine the distribution of input variables using historical data. For example, some of the providers use beta distribution, which requires the estimation of the maximum, minimum and the most likely value of input variables. To capture the effects of uncertainty, samples are drawn from the distribution of the input variables using Monte Carlo methods and a scenario is created. Running a sufficient number of scenarios then produces a stable distribution of long-term market prices. The volatility indices and all the traditional measures are then developed from the statistical distribution of the variable.

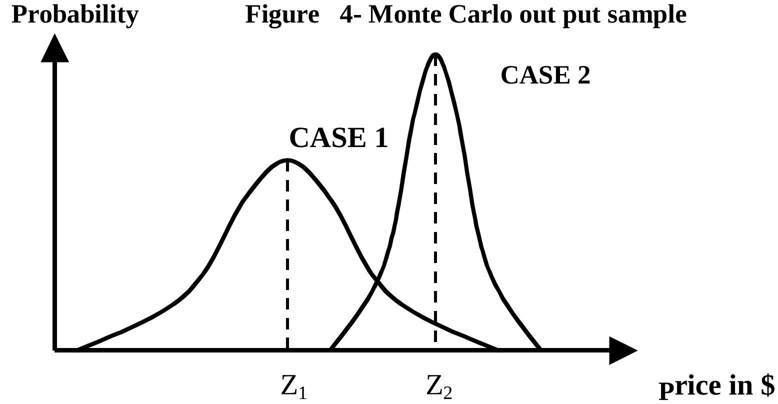
The alternative to Monte Carlo simulation will be direct calculation. In this case one needs to identify a range for input variables i.e. fuel prices and loads and conduct numerous direct calculations. To evaluate each single case we would have to simulate all numbers for all variables, an extremely time and effort consuming procedure. And even if we had all the results, we would still not know the probability of reaching a certain outcome. The Monte Carlo Simulation products provide features that can be used to specify a probability distribution for every input identified as an assumption cell. Then, after running the simulation model, the package automatically performs a statistical analysis for every output we have specified as a forecast cell. By using probabilistic assumptions and analyzing forecasts statistically, the tool helps us gain insights that we could not extract from a deterministic model. These insights lead to better decisions in the probabilistic situations we face in real world applications. Thus the Monte Carlo Simulation reduces calculated time and provides more accurate results.

In the case of this study the Monte Carlo simulation has to be conducted for the following input uncertainties:

- Load Forecast
- Fuel Price Forecast
- Possible system contingencies

Figure 4- provides a sample of out put distribution curves.

Figure 4- Monte Carlo out put sample



The providers of this module are same as market simulation tools.

Other than input data from market simulation output, load forecast output, and fuel price forecast data there is no data requirement for this function. All of the above data shall be available via “automatic links” to this package. The Monte Carlo package is generally included in the market simulation packages described in section 6 of this report. Those initial and maintenance cost for the packages described in section 6 include Monte Carlo functionality.

9. Major Gaps of Tools and Modeling Requirements

This study has identified the some gaps in the implementation of the available tools in the market and other modeling requirements. Specific recommendation regarding the implementation phase for each one of the identified gaps is presented.

2. Source Data

The sources for the required data need to be specified based on identified information and requirements defined in this document. Initially the availability of the data requirements from identified sources needs to be assured. The format of the available data needs to be identified. This format has to be matched with the capability of the considered vendors. During the implementation, some development might be required for the translation or reformatting of data. This activity can be quite labor intensive if the following issues are not considered in the implementation plan of the data:

- Vendors database management tools
- Acceptable formats to vendor
- Specific tools data requirements
- Data format from resources
- Available regular and boilerplate data from vendors

2. Functional Gaps

- One of the major gaps in satisfying the functional requirements is the availability of the subsystems for Electricity Modeling System from one vendor. Majority of the providers for market modeling system do not provide Optimal Power Flow. The challenges and gaps in the implementation of these systems include:

  - Time domains and frequency of calculations. These products use different tools and software products for managing the execution time and frequencies. These tools need to be synchronized.

  - Compatibility with each other, especially in the areas of data format, data requirements, and maintenance tools. The main gap is in the compatibility of the required data. This compatibility needs to be comprehensive enough to enable the users to enter and maintain the data only in one place.

- The majority of the providers do not support the following functional features:

- Fuel constrain modeling in the Electricity Modeling System. Detailed modeling requirement for this feature is provided in section 6.3.3 of this report.

- Modeling of bilateral contracts in the Electricity Modeling System. Detailed modeling requirement for this feature is provided in section 6.3.3 of this report.

- Although the ramping for generation is considered in most of the tools however there have been many reports regarding the inaccuracy of this modeling with most of the available tools. These reports are from generation companies specially when they have implemented the unit commitment module of these systems. Special attention for the requirements definition and implementation of this feature is recommended. Development of a new ramping model based on identified detailed requirements might be needed. This module will be part of Electricity Modeling System.

- Maintenance scheduling of the generating units are supported as a very simplified form, i.e. user entry only by the available products for Electricity Modeling System. Overview of the modeling requirement for this feature is provided in section 6.3.3 of this report. Additional functionality with inclusion of statistical factors might be beneficial for this assessment.

- Modeling of global warming and emission constraints, although very critical for this assessment, are not fully supported by majority of the providers. Detailed modeling requirement for these features are provided in section 6.3.3 of this report. These features are required by Electricity Modeling System.

- Price Responsive Demand and Dispatchable Load are emerging on the electricity market. The modeling of these features as they evolve are very critical for the modeling accuracy specially regarding future studies. Capability to model these activities in the Electricity Modeling System is not supported by the providers (GE MAPS has some limited functionality). Special software needs to be developed to support these programs in different areas.

10. Conclusion

In this report the definition of bottlenecks have been presented. Detailed recommended methodologies and tools for assessment of elimination of bottlenecks have been provided. The modeling and data requirements for each function are provided for each recommended system. These recommendations include all of the viable and available vendors and products in the market. The estimates for costs and human resource estimates are based on personal experience of the assigned consultant. The recommended vendors are result of a screened process conducted by this consultant based on industry knowledge, experience, vendor's track record, and product record. Providers of the commercial products offer different solutions for the following list of features. Detailed definition of the following features during requirements specification is suggested if the recommended solutions in this report are to be implemented:

- Standard Market Design Compliance
- Congestion Management
- Loop Flow
- Price Cap for specific area
- Transmission Additions
- Conservation Plans
- Weather
- Fuel Issues
- Supply side expansion
- Operational Constraints
- Operating Reserve
- Spinning Reserve
- Emission Constraint
- Market Participation
- Purchase and Sale Contracts

- Cost Reconstruction
- Company Model
- Load Model
- Generation Models
- Network Model
- Marginal Cost
- Internal to are trading and flow calculations
- Operating Reserve
- Dispatch
- Dispatch-able Load Management
- Non-dispatch-able Renewable Resources
- Maintenance Scheduling
- Forced Outages
- Hourly Commitment & Dispatch

Due to these shortcomings it is strongly recommended that rather than looking at one provider for all of the solutions a possible consortium of vendors be considered. Unfortunately majority of the providers with viable market simulation tools lack tools with detailed physical power flow modeling. In order to assess economic and congestion conditions strong packages in both areas are required. This issue enforces the justification for considering different providers for each subsystem.

For obtaining accurate results, accurate and complete input data for the utilized software tool is very critical. Usually the data necessary for these studies contain the following:

- Individual characteristic data of all of the individual generators in the studied area. This includes fuel data, incremental heat rate curves, emissions data, ramp rates, limits, etc.
- Individual characteristic data of all of the major loads in the studied area.

- Individual transmission line characteristic data, which is used in power, flow studies.

- Historical data for energy and ancillary prices, loads, load flows, outages, reserves, etc., for the study area.

- Data modeling issues and constraints related to the study areas and regulatory rules.

Gathering this data (if it is available without conflict of interest) is a very time and resource-consuming task. This task will require tens of work-years of effort. After the initial data gathering activity is complete, the maintenance and update of it will be an on-going process and require thousands of work-hours effort every year. The preparation of the data for the selected tool(s) require(s) thorough knowledge and experience of power systems modeling and database building. The process of building data model includes the following critical tasks:

- Decision making, on the control areas and voltage levels to be considered.

- Decision on the total number of buses

- Decision on selection of the source of data.

- Establishment of a process to make the modeling of the systems useable for the future studies.

Prior to these critical decisions important mission and philosophy of building each model for every specific area needs to be analyzed. This analysis needs to be conducted prior to any decision regarding product specification. Some of the critical issues to be defined by this analysis include:

- The division of the whole country's power system modeling to four different regions

- Utilization of the tools like network reduction, database maintenance, and one-line diagrams as part of modeling.

- Environments and processes involving data and model maintenance.

If the recommended methodology is going to be implemented, the consideration of following issues are recommended:

- Decisions regarding modeling regions and details have to be made at the beginning of implementation process. These issues have impacts on some functionality requirements.

- A thorough requirements specification needs to be developed for each one of the subsystems.

- The invited providers shall be strongly encouraged to build a partnership during the proposal and implementation processes. In general there are three major systems that have to work and interface together. Each one of these vendors provides specific functions. These functions have to be compatible with each other specially in the following areas:

    - Time domains and frequency of calculations
    - Data transfer
    - Format of maintained data
    - Utilization of tools like database manager, user interface etc.

- The standards for the implementation of these systems have to be defined and specified before procurement processes. These standards include:

    - Hardware platform
    - Standard software, e.g. operating system, middleware, etc.
    - Database manager, e.g. ORACLE, XCEL, ACCESS, etc.
    - User Interface, e.g. the Web Browser, etc.

- The detailed functionality of every subsystem has to be well defined. As an example considering the modeling of hydro generators, almost all of the recommended vendors model them. Special attention shall be given to specifying the detailed modeling of this feature. The detailed functionality of this feature depends on the modeling detail decision, significance of this feature in the study (since the hydro units play an important role in ancillaries that might be one factor in their significance), the practicality of the requirements, etc. Based on these factors the detailed requirements for hydro modeling shall be defined and matched with proposed solutions.

- The total estimate for implementation of all of the recommended systems and processes is about two years.

Appendix A

Activities Regarding Transmission Planning and Expansion in RTOs and ISOs

1. CA ISO

London Economics has proposed a methodology for CA ISO entitled "Final Methodology: proposed approach for evaluation of transmission investment prepared for the CAISO by London Economics International LLC" in January 2002 (see [2] in Appendix B).

London Economics developed this methodology to evaluating specific transmission proposals within the California ISO control area, having regard to the interdependency between transmission and generation investment, future market uncertainty, market power and issues related to cost and planning uncertainty.

This methodology sets out a framework for evaluating transmission projects. This methodology does not set out in detail the models that will be used for a specific project evaluation, or the detailed modeling steps. The methodology is envisioned, by London Economics, to be applicable using a variety of substitutable modeling software tools, though some may be preferred over others. An in-depth case study of Path 26 upgrades is being conducted. This will put in practice the framework described in the London Economics final report to CA ISO. Expectations are that the modeling and methodological approach will be refined during the first practical studies.

2. ISO NE

ISO-NE has developed and implemented a Regional Transmission Expansion Plan (RTEP) process (see [4], [23] in Appendix B). The RTEP process is intended to provide a "request for solutions" that serves as the market signals appropriate for the planning of generation, Merchant Transmission Facilities, Elective Upgrades, Demand Side Management (DSM) and Load Response Programs (LRP). RTEP summarizes a coordinated transmission plan that identifies appropriate projects for ensuring a reliable electric system and for reducing congestion in an economic manner. The studies that comprise the RTEP reports are conducted with the input and advice of the Transmission Expansion Advisory Committee (TEAC) (see [27] of Appendix B). For reliability studies the GE MARS program is used (see [4] in Appendix B). The General Electric Multi-Area Reliability Simulation Model (GE MARS) was used for conducting this reliability assessment. GE MARS uses a sequential Monte Carlo simulation to compute the reliability of a system comprised of a number of interconnected areas containing generation and load. This Monte Carlo process simulates the year repeatedly (multiple replications) in order to evaluate the impacts of a wide range of possible random generation outage combinations. The transmission system is modeled in terms of transfer limits on the interfaces between interconnected areas. Chronological system histories are developed by combining randomly generated operating histories of the generating units and inter-area transfer limits with the hourly chronological loads. For each hour, the program computes the isolated area margins based on the available capacity and load demand in each area. GE MARS then uses a transportation algorithm to determine the extent to which areas with negative margin can be assisted by areas having positive margin, subject to the available transfer capacity between the areas. The program collects the statistics for computing the reliability indices and proceeds to the next hour. After simulating all of the hours in the year, the program computes the annual indices and tests for convergence. If the simulation has not converged to an acceptable level, it proceeds to another replication of the study year; otherwise, it moves on to the next study year.

The reliability of the pool as a whole is determined by the reliability of the individual Sub-Areas in the pool. In other words, if a Sub-Area is experiencing a loss of load for a given hour because of insufficient generation within the Sub-Area to meet the load for that hour, or because of limits on the amount of assistance that can be imported from other Sub-Areas, the pool itself is considered to be in a loss of load state.

The economic congestion analysis has been performed using a model that provides a balance of physical market infrastructure, economics, and market behavior. The model employed does not focus on the detailed unit level analysis that would be necessary when performing engineering design studies; it does provide a suitable representation of the generator characteristics. This representation allows the impact of bidding behaviors to be considered in the analysis.

3. PJM

PJM has developed and implemented a Regional Transmission Expansion Plan (RTEP) process (see [13] in Appendix B). This process consolidates the transmission needs of the region into a single plan. The RTEP reflects transmission enhancements and expansions, load and capacity forecasts, and generation additions and retirements for the ensuing ten years. This plan provides a 5- year plan to address needs for which a commitment to expand or enhance the transmission system must be made in the near term in order to meet scheduled in service dates. The plan also provides a 10- year working plan that addresses the needs for transmission enhancement and expansion for which commitments would not be required in the near term. Commitments needed in the first 5 years to complete work scheduled for years six through ten will be included in the 5- year plan. The PJM RTEP provides an assessment based on maintaining the PJM Control Area's reliability in an economic manner. The plan is targeted to avoid any unnecessary duplication of facilities. It also avoids the imposition of unreasonable costs on any Regional Transmission Owner (RTO) or any user of transmission facilities.

PJM has conducted a ten-year transmission adequacy study for 1997-2006 (see [12] in Appendix B). The 1997-2006 PJM Transmission Adequacy Assessment provides a 10-year forward-looking evaluation of the planned transmission system's ability to meet customer energy and demand requirements in light of reasonably expected outages to system facilities.

Generation plans, transmission plans, and load forecasts, which were available to PJM Interconnection, L.L.C. as of June 1, 1997 provided the basis for system models upon which the analysis for this report was performed.

Four methods of analysis were used to measure the transmission system's capabilities and to identify the facilities that cause limitations to the transmission system capabilities. They were as follows:

- Deliverability (CETO/CETL)
- First Contingency Incremental Transfer Capability
- PJM Emergency Import Capability
- Congestion Analysis

The main body of the 1997-2006 PJM Transmission Adequacy Assessment report (last 4 of the front 6 sections) devotes an entire section to each of the four methods of analysis. Each of these sections begins with a brief description about the purpose, procedure, and assumptions associated with the subject analysis, and then proceeds to provide a summary and assessment of the significant results. Each of these sections also has a companion appendix (A through D) that provides more detail about the analysis method and a complete listing of the results, which were obtained.

4. NY ISO

The NY ISO has provided a report (conducted by an external contractor) regarding congestion costs (see [10] in Appendix B). This report provides an estimate of the congestion costs in New York for the years 2000, 2001, and partial 2002 and the attribution of these costs to the causative physical transmission constraints.

Congestion cost in this study means the premium paid by New York load due to the inability of the transmission network to deliver the lowest price generation to the demand points. All analysis was confined to costs in the Day Ahead Market (DAM). No consideration of losses was included in this study. While the results are estimates, and only based on publicly available data, they are useful for informing the transmission planning process and improving congestion management practices. The total congestion cost, provided by this report, for New York has been estimated at $1,240M for year 2000, $570M for 2001, and $451M for the first half of 2002.

NY ISO has also conducted a study regarding impact of the generation expansion scenarios on the transmission system (see [8] in Appendix B). This study is conducted using GE MAPS program.

In another case NY ISO has conducted a study in 2002 reviewing the New York State Bulk Power System Transmission System in the year 2007 (see [7] in Appendix B). The thermal limit analysis of this study was conducted PTI MUST program. The voltage analysis was conducted using PTI's PSS/E (Rev. 28) in conjunction with the NYISO Voltage Contingency Analysis Procedure (VCAP). Analysis of the NYCA extreme contingencies was performed using Power Technologies Incorporated Power System Simulator software, PSS/E. Each contingency was tested for dynamic stability, voltage, and thermal limits.

5. ERCOT

ERCOT has established a transmission planning process (see [6] in Appendix B). The ERCOT ISO (ISO) will supervise and exercise comprehensive authority over the overall planning of bulk transmission projects that affect the transfer capability of the ERCOT transmission grid (transmission system). To accomplish this the ISO will:

- Study and monitor the transmission system for current and future constraints
- Consider new transmission proposals submitted by interested parties
- Supervise the processing of all requests for interconnection to the transmission system from owners of proposed new generating facilities, including performing or coordinating any applicable system security studies
- Recommend needed transmission facility additions based on identified constraints, proposals by transmission providers and requirements for integrating new generating facilities into the ERCOT system
- Conduct an open process of public review and comment on proposed facility additions
- Submit all final recommended transmission facility additions to the ERCOT Board of Directors for review and concurrence
- Determine the designated providers of the additions
- Notify the Public Utility Commission of Texas (PUCT) of all Board supported transmission facility additions and their designated providers

Transmission additions will be considered when studies show that a contingency on the transmission system will result in one or more of the four conditions listed above despite reasonably expected generation additions. Transmission additions will be considered when significant excess generation is constrained inside an area where forecasted load fails to materialize as anticipated or where load growth cannot be met by sufficiently competitive new generation as a result of inability to site generation in that area. Transmission additions may be indicated when the studies show a disproportion in the amount of transmission capacity to load into a load area.

ERCOT has identified a number transmission constrains. The proposed solutions are being studied using simulation tools. This study has not had access to the name of providers or tools used in these studies.

Appendix B

References

1. National Transmission Grid Study, U.S. Department of Energy, The Honorable Spencer Abraham Secretary of Energy May 2002
2. Final Methodology: proposed approach for evaluation of transmission investment, prepared for the CAISO by London Economics International LLC 2002
3. Comments on the London Economics Methodology for Assessing the Benefits of Transmission Expansions By Frank A.Wolak; Brad Barber; James Bushnell; Benjamin F. Hobbs, Market Surveillance Committee of the California ISO, 2002
4. ISO-NE Regional Transmission Expansion Plan (RTEP) report, posted on November 2002.
5. PJM Interconnection, LLC 1997-2006 Transmission Adequacy Assessment 1997-2006 PJM
6. ERCOT ISO Transmission Planning Process, Approved by ERCOT Board 8/26/99
7. New York Independent System Operator 2002 AREA TRANSMISSION REVIEW OF THE NEW YORK STATE BULK POWER TRANSMISSION SYSTEM IN THE YEAR 2007 (NYISO INTERMEDIATE TRANSMISSION REVIEW) Prepared by the NYISO Transmission Planning Staff
8. Implications of capacity additions in New York on Transmission System Adequacy, A MAPS Study performed for NY ISO
9. Investigation of Potential Low Cost Transmission Upgrades Within the New York State Bulk Power System Interim Report, Transmission Planning Analysis & Planning Department, NY ISO
10. Project Report New York Congestion and *Physical Constraint Cost Estimates* Prepared for New York Independent System Operator (NY-ISO), Submitted by Manos Obessis
11. NY ISO, Transmission Expansion and Interconnection manual
12. PJM Interconnection, LLC 1997-2006 Transmission Adequacy Assessment 1997-2006 PJM TRANSMISSION ADEQUACY ASSESSMENT *Prepared by:* System Coordination Division
13. PJM 2001 BASELINE RTEP REPORT For the 2002 - 2006 Period March 5, 2002
14. Transmission System Operations and Interconnection. National Transmission Grid Study Alvarado, F. and S. Oren. 2002, U.S. Department of Energy.
15. Moving Toward Seamless Energy Markets: Evidence from the Northeast, Bailey, M. and C. Eaton. 2001 Electricity Journal, v. 14, #6, July.
16. Advanced Transmission Technologies. U.S. Department of Energy. Hauer J., T. Overbye, J. Dagle, S. Widergren. 2002.
17. Transmission Siting and Permitting David H. Meyer, Richard Sedano
18. Transmission Planning and the Need for New Capacity. U.S. Department of Energy. Hirst, E. and B. Kirby. 2002.
19. "Optimal Power Flow (OFP) Algorithm of UPLAN-E: Theory and Application", Rajat K. Deb, technical report, 1997
20. "Power Generation and Control", Allen J. Wood and Bruce F. Wollenberg.
21. The Market for Spinning Reserve and its impacts on Energy Prices, Jinxiang Zhu, Gary Jordan, Satoru Ihara, IEEE Winter Meeting 2000
22. Forecasting Locational Marginal Prices in a US ISO, Jeffrey Bastian, J. Zhu, V. Banunarayanan CIGRE, 2000.
23. The Role of ISO New England in Planning the New England Bulk Power System Douglas James ISO New England, Inc Prepared for the Joint ISO Planning Working Group February 17- 18, 2000.

24. Problems with Monte Carlo Simulation, Renwick E. Curry, Journal of Financial Planning, Nov. 2001.
25. A comparison between the approaches adopted by the US Federal Energy Regulatory Commission and the European Commission to complete the internal electricity market. Yvan Chaxel University of Chicago, May 2001
26. MARKET-BASED TRANSMISSION INVESTMENTS AND COMPETITIVE ELECTRICITY MARKETS WILLIAM W. HOGAN August 1999, Center for Business and Government John F. Kennedy School of Government, Harvard University
27. TEAC meetings minutes from PJM
28. TEAC meetings minutes from ISO NE
29. PJM's Customer Load Reduction Pilot Program (Draft Report)
30. NYISO Price-Responsive Load Program Evaluation Final Report, Prepared by Neenan Associates, LLC January 8, 2002