filed within the time required herein, if the Commission on its own review of the matter finds that permission and approval for the proposed abandonment are required by the public convenience and necessity. If a motion for leave to intervene is timely filed, or if the Commission on its own motion believes that a formal hearing is required, further notice of such hearing will be duly given.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for Transco to appear or be represented at the hearing.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–10899 Filed 4–23–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. PL98–6–000]

Inquiry Concerning the Commission's Policy on the Use of Computer Models in Merger Analysis; Notice of Request for Written Comments and Intent To Convene a Technical Conference

The Federal Energy Regulatory Commission (Commission) hereby announces that it is requesting comments on the use of computer models in merger analysis and intends to convene a public conference to discuss this matter. The purpose of this inquiry is to gain further input and insight into whether and how computer models should be used in the analysis of mergers, including whether computer models can be useful in a horizontal screen analysis that follows the Appendix A guidelines of the Merger Policy Statement.[1]

We are issuing this request concurrently with the Notice of Proposed Rulemaking on Revised Filing Requirements Under Part 33 of the Commission's Regulations (Docket No. RM98–4–000). In that NOPR we identify the use of computer models as an emerging issue in the analysis of mergers. We are issuing this notice concurrently in order to inform the Commission's understanding of the current and likely future role played by computer models in merger analysis. The attachment to this notice provides a framework for discussion of models and includes a sample model intended to serve as a starting point for discussion and comment.

I. Introduction

The use of computer models—specifically, computer programs used to simulate the electric power market—has been raised in comments on the Policy Statement and also in specific cases. In comments on the Policy Statement, the Department of Justice (DOJ) recommended using computer simulations to delineate markets. DOJ also noted that these simulations could be helpful in gauging the market power of the merged firm.[2]

In *Primergy*, the applicants used a computer simulation in their market power analysis. We did not accept the results of this computer simulation, in part because we felt that the model was not properly structured or tested. However, it was not our intention to inhibit the use of computer models. We emphasized that ''we do not wish to discourage the development of computer models for use in merger analysis''.[3]

The Commission continues to believe that a properly structured computer model could account for important physical and economic effects in analyses of mergers and may be a valuable tool to use in horizontal screen analyses. A computer model could be particularly useful in identifying the suppliers in the geographic market that are capable of competing with the merged company. A computer model may also provide a framework to help ensure consistency in the treatment of those data in identifying suppliers in a geographic market.

Two important ways in which a computer model could improve the accuracy of the delivered price test are: (1) by explicitly representing economic interactions between suppliers and loads at various nodes in the transmission network and (2) by accounting for the transmission flows that result from power transactions. We discuss these and other matters in greater detail in the Attachment.

Interactions between suppliers and loads. In competitive markets for electric energy, decisions about what suppliers would serve what loads are likely to be driven by short-run marginal costs, including the opportunity cost to suppliers of serving one load rather than another. Because there can be many possible combinations of supplies and loads, some form of computer model could be helpful in estimating such combinations.

Transmission flows from exchanges of power. Because of the properties of electric power flows, exchanges of power between control areas affect flows throughout the transmission grid. Any reasonable approximation of these effects may require a computer model to make the many calculations needed to simulate the electric power flows.

Developing and using a computer model involves a number of choices about the structure of the model, the level of detail reflected in the model, the sources of information, and other issues. These issues are discussed in the Attachment. If these technical aspects of model design and development can be addressed adequately, a computer program could be helpful in defining geographic markets. One common approach to market simulation, discussed further as an example in the Attachment, is to model the dispatch of generation to meet loads in the transmission network. The simulation model in the example estimates market outcomes that minimize the total cost of generation and transmission. The contribution of such a program to a delivered price analysis is illustrated by briefly describing the output information that the model could provide. Typical output from a program could consist of the following:

- Generation levels. The computer model would show the level of output of each generator.
- Power traded. The model would show the net quantity of power traded between interconnected areas[4] under economic dispatch.
- Flows on the transmission grid. The model would show the quantity of power flowing through each transmission facility represented in the model, constrained by any transmission capacity limits that have been input to the model. The effects of binding limits would be reflected in model output of generation levels and power prices.
- Prices for power. For each area, the model would show the marginal cost of power. This price can also be interpreted as the market-clearing price for the area.

II. Request for Written Comments

If a computer model were available to produce the types of output described above, we believe that its use could both enhance and potentially expedite delivered price analyses. However, the

[1] Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996), *order on reconsideration*, 78 FERC ¶ 61,321 (1997) (Policy Statement).

[2] Appendix to DOJ Merger NOI Comments at A–11, n12.

[3] Wisconsin Electric Power Company, *et al.* (*Primergy*), 79 FERC ¶ 61,158 at 61,694 (1997).

[4] Typically, the interconnected areas would be control or planning areas, but the exact geographic area would depend on how the model was implemented.

Commission also recognizes that there are many technical and procedural questions that need to be addressed concerning whether and how to use a computer model in merger analysis. To assist in the discussion of these issues, the attachment presents an overview technical discussion, followed by a list of questions for comment. These questions are organized into five areas: basic model structure, alternative implementations of the basic structure, data issues, application of models to merger analysis, and model development and maintenance. All interested persons are invited to submit written comments (not to exceed 25 pages) on these questions and any other issues that the Commission should be considering with regard to computer models and merger analysis. Comments must be filed on or before June 14, 1998, in Docket No. PL98–6–000. All comments will be placed in the Commission's public files and will be available for inspection or copying in the Commission's Public Reference Room during normal business hours. Comments are also accessible via the Commission's Records Information Management System (RIMS).

III. Intent To Convene Technical Conference

The Commission intends to convene one or more technical conferences to discuss the use of computer modeling. We will issue a notice of conference at a later date.

By direction of the Commission.

Linwood A. Watson, Jr.,

Acting Secretary.

Attachment: Computer Modeling and Merger Analysis

The purpose of this attachment is to present a sample computer model as a starting point for discussion of issues and questions about how such models could be helpful in merger analysis, specifically in reference to the Commission's delivered price test and potentially in other aspects of merger analysis. This attachment is a Commission staff paper intended to facilitate technical discussion. Specific comments on the sample model should be considered in light of the questions raised at the end of this attachment.

Background and Organization of Attachment

This Attachment discusses computer models and their use in merger analysis. A computer model is a computer program designed to implement a specific mathematical procedure. The specific procedures discussed here are typically called ''models'' because they are, or at least contain, abstract representations of real world processes. We concentrate here on two such processes: power markets and electric power flows over transmission networks. Computer models hold great potential in merger analysis because they can simulate both market processes and the electric power flows that results from market processes.

Computer models of electricity markets and networks have many potential uses, but we are primarily concerned here with how the market simulations produced by such models can be used in performing a delivered price test described in the horizontal analysis section of this NOPR. In the context of a delivered price test, computer models—in the sense of simulations of markets or electricity networks—must be distinguished from other types of computer programs. A wide range of computer programs could be used to automate parts of the delivered price test. For example, a computer program could be used to identify all generating units that could supply a destination market at a particular price, given the variable cost of power at each plant, and the transmission cost to the destination, as inputs. Such a program would not typically be called a model, because it does not simulate either market interactions or electricity flows.

For purposes here, the computer models for our consideration can be grouped into three broad categories:

- Electricity Market Models. These models simulate electricity production and trade between regions, but do not attempt to represent the underlying electricity network in the model. Examples of such models include the Electricity Market Model (EMM) from the Energy Information Administration (EIA), and the more detailed Policy Office Electricity Model (POEMS) developed for the Policy Office of the Department of Energy.
- Electric Power Production/Transmission Power Flow Models. Generally, these are detailed models that simulate electric power generation and/or electric power transmission, but do not attempt to represent the market interactions or power trade between regions. There are several models that implement standard power flow simulation techniques.[1] Detailed production cost models (*e.g.*, PROMOD and GE-MAPS), when they are designed for detailed cost analysis of a single utility, could also be placed in this category.
- Hybrid Models. Hybrid models combine a market simulation component with an electricity production and transmission component. We know of no standard model designed specifically for this purpose. Some production cost models, such as GE-MAPS, have been expanded beyond single utility territories and used as simulations of a competitive regional electricity market. However, these models remain highly detailed and may be more difficult to use for simulating electricity market trading of electricity over large regions than a regional market model with a more aggregated representation of the power transmission network. We seek comment on currently available models in the questions at the end of this attachment.

For examining the competitive aspects of mergers, hybrid models are the computer models of interest, because both market processes and actual power flows are important for the analysis. To understand the role of a computer model in the analysis, it is essential to distinguish between the computer model itself and its application. A run of the computer model simulates power generation and power transmission for a particular scenario. The outputs from the simulation are then applied to a particular problem—for example, power generation and transmission levels from the simulation output might be used in the identification of suppliers in a delivered price test. In this attachment, we will restrict the use of the term computer model to the first function—simulating results for a particular scenario—but also discuss how these simulation results could be used in a delivered price test. In addition, we seek comment on other potential uses of a computer simulation model in the competitive analysis of mergers.

This attachment describes one type of computer simulation model we have been considering and its potential use in merger analysis. It then raises a series of questions about the framework and examples presented. These questions are intended to serve as a guide for commenters and perhaps for discussion at technical conferences on computer modeling and merger analysis. The Attachment is organized into five sections, as follows:

- Overview of a modeling framework for electric power trading over a transmission network. This framework is presented to facilitate a discussion of whether the Commission should consider a computer model for use in the analysis of mergers, and what role a computer model, if utilized, should play in the analysis.
- Description of a simple model implementing the general framework, presented both qualitatively and as a mathematical formulation. The purpose of this simple example is to provide a structured starting point for technical questions about the design and development of a more complex simulation model for use in merger analysis.
- Data considerations in model implementation using currently available public sources of data. This section discusses the data needed for a computer model and the availability and limitations of publicly available data.
- Application of a computer model in merger analysis. This section addresses the question of how computer model simulation runs would play a role in a delivered price test.
- Questions for discussion at a technical conference or conferences. These questions extend the earlier discussion by asking questions about the design and development of the framework and sample model, how a model should be used in the competitive analysis of mergers, what data sources are available, and how the Commission should proceed in developing and maintaining a model.

Overview of Model Structure

The role of computer modeling in merger analysis can be identified by first reviewing

[1] For example, the FERC Office of Electric Power Regulation uses a load flow program called PSLF from General Electric that is a package of programs handling loadflow, fault analysis, and stability calculations.

the Commission's delivered price test. For a delivered price test, applicants are expected to estimate the cost of economic transactions to acquire power and transmit it to a destination, and also to determine how much power is available to be generated and transmitted to a destination, given the limitations on power transactions imposed by the transmission system. For example, given a particular destination market, an applicant should:

• Determine an appropriate competitive price for wholesale electric power in that destination market that is consistent with available information, and adequately support the method used to determine the price.

• Estimate the available generating capacity and variable cost of wholesale electric power from potential supplier facilities at the level of individual generating units to the extent possible.

• Estimate the cost of transmitting power (including ancillary services) from the source of generation to the destination, using maximum applicable tariff rates or other conservative estimates that can be supported.

• Make other adjustments, as appropriate, to reflect a supplier's competitive presence in a destination market, and support such adjustments with adequate analysis, data and assumptions, and

• Evaluate the impact of transmission system limitations on the ability of potential suppliers to deliver power to the destination market, using simultaneous estimates of transmission capacity limits to the extent possible.

These requirements help delineate a framework for analyzing electric power transactions over a transmission network. This process of analysis can be made more explicit by first constructing a general representation of the analysis and then incorporating this general picture in a mathematical formulation of the economic problem and the constraints imposed by the physical electricity transmission system limits. Figure 1 gives a general representation of the problem of combining the analysis of electric power transactions with an analysis of the physical limitations imposed by the electric transmission grid. The upper diagram represents the economic network of power transactions, that is, the production and consumption of power in each area, as well as trades of power between interconnected areas. The amount of trading that occurs among areas depends on the load requirement of each area, on the price and availability of power in each area, and also on the cost of transmitting power between the areas. The lower diagram represents the actual physical transmission network in which these economic transactions occur. It would comprise primarily the transmission lines and transformers that are called ''flowgates.'' Transactions between areas (in the upper diagram) cause flows across these flowgates in the physical network (in the lower diagram). These flows are then subject to the actual physical limits imposed by the electric transmission network.

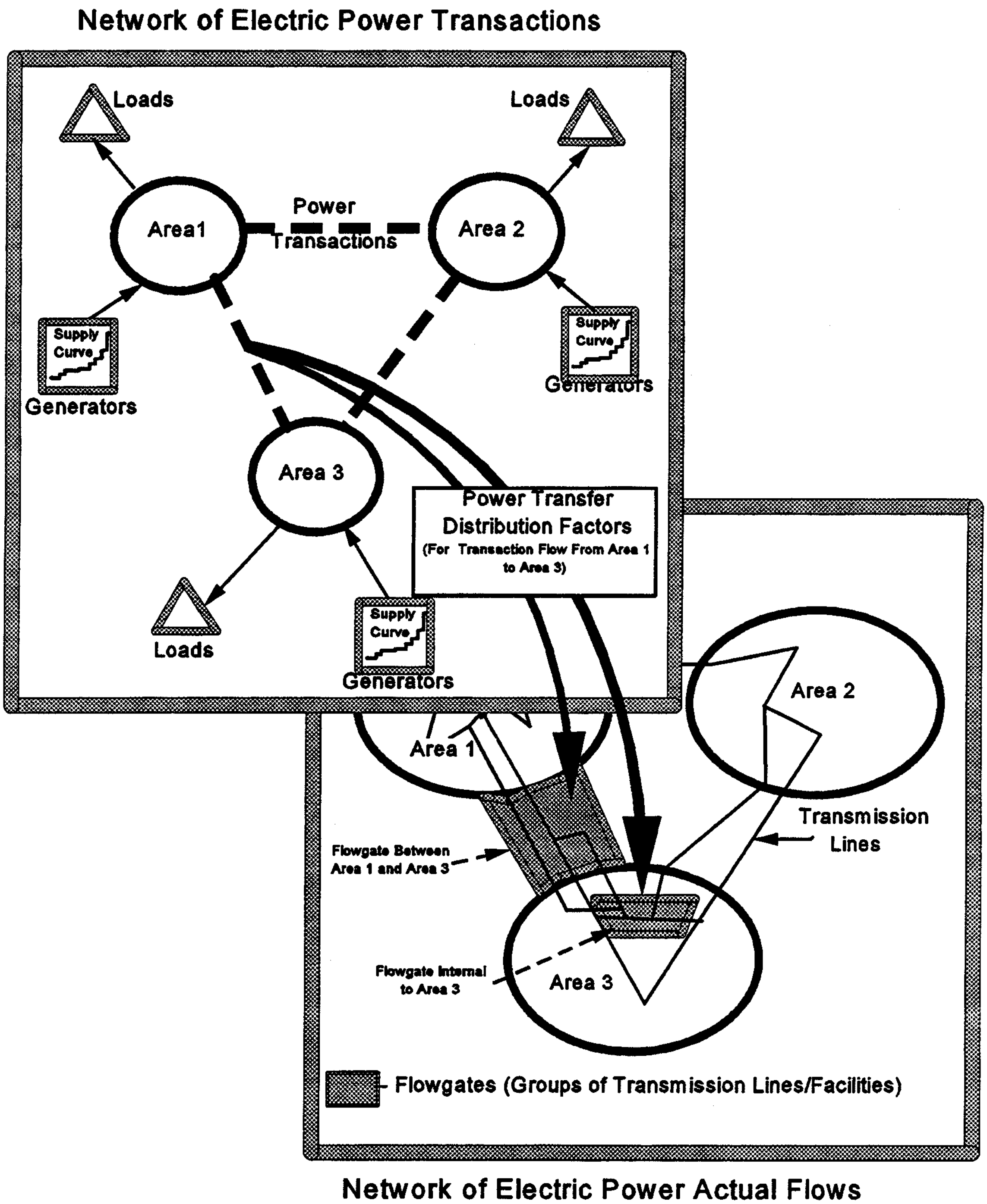
Most of the key elements in the Figure 1 are the same elements that would need to be considered in a delivered price test without a computer model. In order to explain the structure shown in Figure 1, we explain these common components first:

Areas. These are locations in the transmission network where electric power is injected by generators and withdrawn by loads. Although in principle they can be any part of the network for which generation and load data are available, in practice they often correspond to control areas. In any case, the considerations that go into defining the locations of generating plants and loads can be the same, whether or not a computer model is used to conduct a delivered price test.

Generators. In Figure 1, the generators located in each area are shown as supply curves. In the model, the width of each step on the supply curve would correspond to the capacity of a specific generator located in an area. The height would correspond to the variable cost of power from that generator. To construct a supply curve, generators may be arranged in order of the variable cost of generation, just as they would be for a delivered price test without a computer model. Supply curves can be constructed in others ways, and we seek comment on such alternatives.

BILLING CODE 6717–01–P

Figure 1. Electric Power Transactions and Transmission Flows



BILLING CODE 6717–01–C

Loads. Loads in Figure 1 represent demands to be met by generating power and transmitting it over an electricity network. Although a computer model of power transactions would be expected to include more than just destination market loads explicitly considered in setting the destination market price, the information sources for these loads should be the same as the sources for a delivered price test without a computer model.

Power Transactions/Area Interconnections. The specification of interconnections and the cost of transmitting power between areas included in the analysis should be the same with and without a computer model. In particular, transmission prices should represent a conservative estimate of the cost of transmitting power (e.g., by using maximum tariff rates).

As noted above, a computer model of market interactions would contain more loads than just those at a particular destination. To be adequate, it should represent all relevant loads that would have a significant impact on the market for power at a destination. This type of computer model could then calculate the suppliers' opportunity cost of selling power, and market prices that reflect these opportunity costs, because the cost of power at each destination would be considered in the model. Although this opportunity cost can be informally considered as an adjustment to a supplier's competitive presence when doing a delivered price test without a model, a model removes the ambiguity in this informal consideration by explicitly calculating the opportunity cost.

A computer model should also represent the physical electrical network and model the relationship between power transactions and actual power flows and the limitations on power transactions that must be imposed when actual power flows approach transmission capacity limits. These two considerations—the relationship between electric power trading and physical power flows, and the effect of transmission capacity limits—should be included in any analysis of a merger to the extent that information is available. One value of a simulation model lies in incorporating both of these considerations in the computer program, where the needed calculations can be performed in an efficient, standard way. The treatment of transmission flows and limits in the computer simulation model are discussed in more detail below.

Estimating Transmission Flows from Power Transactions. The model structure presented in Figure 1 shows the link between transactions and transmission using power transfer distribution factors (PTDFs). As shown in Figure 1, these factors are used to superimpose the effect of power transactions shown in the upper diagram on the underlying electricity network shown in the lower diagram of the figure. These flows may be on individual lines or groups of lines.[2] The lines represented in a computer model may correspond to tie lines between areas, but they may also correspond to other lines in the transmission network that are internal to areas and not part of an interface between areas.[3]

Figure 2 shows how the PTDFs are applied. The exchange of power between areas shown on the left side of the figure corresponds to the injection of power (100 MW in the example) into the transmission grid in Area 1 and the withdrawal of the same quantity of power in Area 2.[4] Because of the nature of the electricity flows in networks, this exchange of power induces flows on all lines in an interconnected grid. While a precise estimate of the electricity flows from a specific change can only be determined from a complicated power flow model, the flows can be approximated by a standard modeling technique, known as the DC Load Flow model.[5] Distribution factors can be used to capture the DC Load Flow estimates as shown in Figure 2. The quantity of flows on each line in the actual transmission network is estimated by multiplying the quantity exchanged by a PTDF. For example, 70 MW of the 100 MW power (a PTDF of 0.7 times power trade 100 MW) exchanged between Area 1 and Area 2 flows on the lines from Area 1 to Area 2.

The Distribution Factor Task Force of the North American Electric Reliability Council (NERC) estimates PTDFs for input into the interim Interchange Distribution Calculator (iIDC).[6] A computer program for market and merger analysis could use these PTDFs, but other forms of distribution factors are standardly used in DC load flow analysis.

[2] Groups of lines are referred to here as ''flowgates,'' discussed further below.

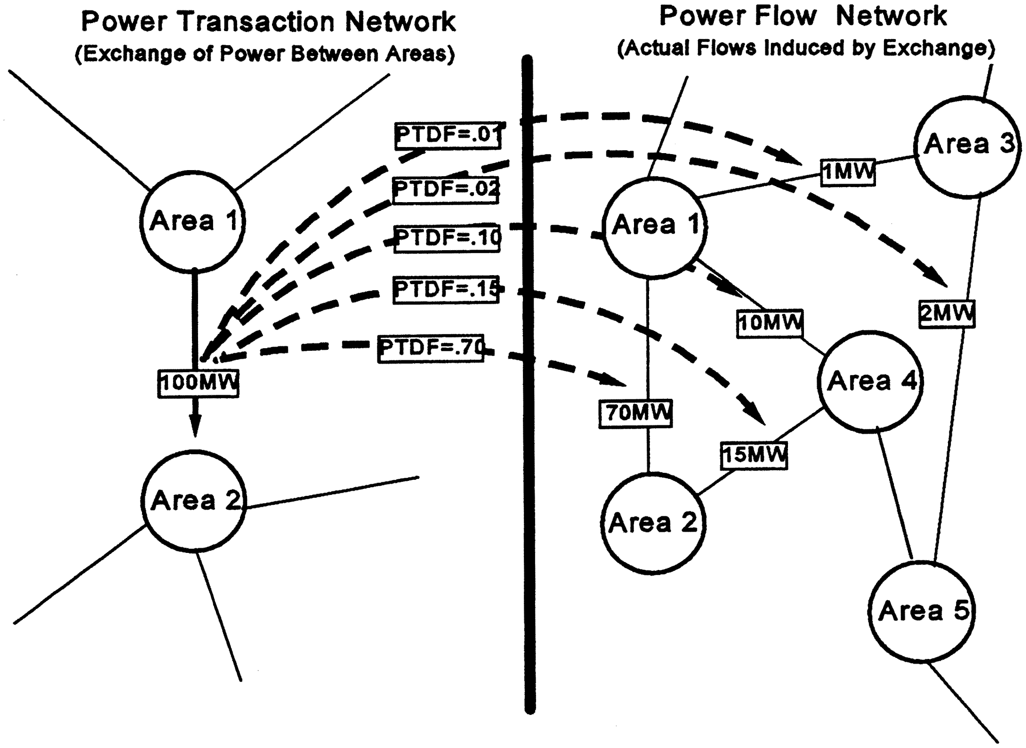
[3] For example, in the DC flow model used by the NERC to generate the draft PTDFs, 20 transmission lines make up the flowgate representing the interface between APS and PJM, 12 lines represent the interface between APS and AEP, 3 lines make up the interface with Ohio Edison, 3 lines make up the interface with Duquesne and 7 the interface with Virginia Power. In addition to tie line flowgates, the NERC model includes 34 flowgates representing lines internal to the APS control area.

[4] For purposes of the example and discussion, we are ignoring losses.

[5] See Fred C. Schweppe, Michael C. Caramanis, Richard D. Tabors and Roger E. Bohn, *Spot Pricing of Electricity*, Kluwer Academic Publishers, Boston, 1988. Appendix D describes the DC Load Flow.

[6] NERC plans to use the iIDC to support a flow-based transmission reservation and scheduling process and line loading relief procedures. In response to an NERC Board of Trustees recommendation, the Engineering Committee and Operating Committee approved the creation of a Transmission Reservation and Scheduling Task Force to ''develop a process for the reservation of transmission services and scheduling of energy transfers recognizing the actual use being made of the Interconnection''. The task force developed a detailed recommendation for a flow-based transmission service methodology (FLOBAT) based on flowgates and PTDFs. See ''Transmission Reservation and Scheduling, Transmission Reservation and Scheduling Task Force'', Report to the Board of Trustees, December 12, 1996.

Figure 2. Example of Applying PTDFs to A Power Transaction



We seek comment on the most appropriate source for information on distribution factors for modeling purposes.

Transmission Capacity Limits. NERC has compiled distribution factors for the Eastern Interconnection [7] that relate control area power exchanges to flow across area tie lines and their corresponding flowgates. These flowgates are groups of transmission facilities that are monitored for security purposes. Using these factors, it should be possible to model flows at points in the transmission system that are most likely to constrain the economic use of the transmission grid. These flows become important for market analysis when any flows reach a physical limit on the flowgate. When the limit is reached, power must be redispatched if the destination loads are to be met. Redispatching power means changing which generating units produce power, so that power generation does not cause transmission flows to exceed the limit on the flowgate.

The physical limit on a flowgate is not a simple, static quantity. Flowgate limits are set for individual elements of the transmission network to assure they are not operated beyond safe loading, depending upon such cond itions as thermal limits, generating resource availability, line outages, loop flow, stability and voltage conditions, and so on. Because the limits reflect system conditions at any point in time, the limits are dynamic and care must be exercised if single quantities limits are used in a computer model. These considerations about the nature of transmission limits are not limited to the particular example of flowgates; they apply as well to the Total Transfer Capability (TTC) and Available Transfer Capability (ATC) quantities posted on OASIS. We focus here on flowgate limits because they appear to be the limits most directly related to the distribution factors used to estimate network flows. Other approaches to estimating physical flows and associated limits are possible; we ask questions about such approaches in the last section of this attachment.

NERC is developing an Interregional Security Network (ISN) that may include data on flowgate capacities, but these limits are not currently available. Estimates of the capacity limits of these flowgates are important data for the implementation of a model based on that network. The availability of these limits would be of considerable value even if a model is not used, since they could be used to estimate limits on transmission flows for many types of analysis of transmission grid transactions, including conducting delivered price test without a model.

Specification of a Simple Model

The two main benefits of implementing the electric power modeling framework through a computer program are: (1) Better representation of the market interactions, in particular the opportunities presented to suppliers by the presence of other loads in addition to the loads at the destination market and (2) better representation of the impact that transmission limits will have on economic transactions. In order to make the general structure specific for use in a computer program, the mathematical structure of the algorithm must be described and the data used as input to this algorithm must be specified. As a starting point for discussion, this section describes an algorithm that can be implemented using most standard mathematical programming software packages. The algorithm is described qualitatively and also presented as a mathematical formulation.

The problem solved in this example is finding the lowest cost combination of supplies (generating plants) and power transactions between areas, to meet fixed demand (loads) over an electricity transmission network, given costs for power, charges for transmission of power within and among areas,[8] transmission loss factors, and physical limits to moving the power over the grid. Solving this cost minimization problem simulates the actions of a competitive market. Under this least cost dispatch, buyers of power can't make any more trades among suppliers to lower their purchase costs. This is the expected result in a purely competitive market, where buyers have alternatives and are permitted to trade among these alternatives until they get the best value for their money.

In the ''real'' world, conditions are more complex than in a computer program. The clearest differences between generation and transmission in the computer program and the real world are assumptions about information (the model assumes it is perfect and costless) and the cost of transactions (the model assumes no costs for searching for

[7] The Eastern Interconnection is the portion of the transmission grid that covers the eastern part of North America, extending from the Rocky Mountains to the Atlantic Ocean (but excluding the Electric Reliability Council of Texas (ERCOT)).

[8] As discussed above (page 4), these areas would typically be control areas. Since the sample model is general, we drop the specific qualifer.

suppliers, negotiation of trades, or costs of interruption.) The computer model makes any trade that can lower costs, even if it involves large and complicated combination of individual trades among buyers and generators across a transmission network. Even simple transactions are assumed to involve only variable costs of generation and maximum transmission rates.

While these idealizations are limitations, some idealizations of this sort are inevitable, and point out the need to view computer simulation model as a tool in an overall analysis. These issues can be addressed with model runs where assumptions change—i.e., by conducting sensitivity analysis under different scenarios. In addition, computer program results need to be validated by checks against other sources of market information before making use of the outputs from the program.

The model specified here is a basic model that could be used to examine electric power transactions and transmission flows. This model is presented as a ''strawman'' point of departure for discussion. It represents only a single period solution of the problem, that is, it does not attempt to address startup costs or other multiple period effects. It also includes some parameters as a single constant that may need to be varied across areas, for example, adjustments for losses. Further, other factors would need to be addressed through adjustment of input data (for example, through adjustments to plant capacities for availability in each time period analyzed). These issues will be raised below in the section on issues and questions for comment. However, even without such modifications, staff believes that this basic model does capture important market and transmission effects. Even the use of a simple model, not much more complex in structure than the model presented here, could potentially enhance the delivered price test and expedite the analysis of mergers, if data are available to implement the model. In the next section we discuss data issues related to this implementation.

The objective of the model, the constraints that must be met in reaching this objective, and the model inputs and outputs are described below. The model is stated mathematically in Figure 3.

Model Objective. Minimize the total cost of delivered power, calculated as the sum of generation and transmission costs to meet a fixed set of demands (loads) in each area, given costs for power generation in each area and rates to transmit the power between interconnected areas.

Subject to constraints that satisfy:

Generation capacity requirements. Generation does not exceed a maximum capacity for each unit or fall below a minimum level if one is specified.

An energy balance in each area. The sum of generation in each area plus power imported from other areas over the transmission network, adjusted for losses in generation and transmission, is equal to the demand in each area.

Flowgate requirements. The flow across the flowgates defining the electricity network does not exceed the maximum flowgate capacity or fall below the minimum flowgate level if one is specified.

Transmission system balance requirements. The total power injected into the transmission system equals the total power withdrawn from the transmission system, adjusted for losses.

The model inputs needed to compute the objective function and determine the constraints are:

- The variable cost of generation at each unit in each area.
- The capacity of each generating unit in each area (and the minimum run level if needed).
- The demand (load) in each area.
- The applicable transmission rate between each pair of interconnected areas.
- Power transfer distribution factors for each interconnection between control areas.
- Losses in generation and transmission.
- The maximum capacity of each flowgate.

BILLING CODE 6717–01–P

Figure 3. Power Transaction and Transmission Model Specification

Variables, Parameters and Limits: 9/

x_{ij}	=	transaction flow from area i to area j	$Fmax_m$	=	maximum flow at flowgate m
R_{ij}	=	transmission tariff rate ($/MWH) from area i to area j	$Fmin_m$	=	minimum flow at flowgate m
q_{ki}	=	production from unit k at area i	A	=	Reference area for measuring flow gate constraints, injections and withdrawals
D_i	=	demand at area i	F_{im}	=	the flowgate factors for an injection in area i and a withdrawal in area m
C_{ki}	=	cost ($/MWH) of unit k at area i	α	=	Fractional transmission losses in area interchange
$Qmax_{ki}$	=	maximum production of unit k at area i	β	=	Fractional transmission losses within each area
$Qmin_{ki}$	=	minimum production of unit k at area i			

Objective Function: Minimize Total Cost of Generation Plus Transmission

$$\sum_i\sum_k C_{ki}\, q_{ki} + \sum_i\sum_j R_{ij}x_{ij}$$

Subject to:

Energy balance for reference area

Injections: $x_{iA} - \sum_j x_{ij} = 0, \forall_i$ Withdrawals: $x_{Aj} - \sum_i x_{ij} = 0, \forall_j$

Flowgate constraints

Maximum: $\sum_i F_{im}(x_{iA} - x_{Ai}) <= Fmax_m, \forall_m$ Minimum: $\sum_i F_{im}(x_{iA} - x_{Ai}) >= Fmin_m, \forall_m$

Generator constraints

Maximum: $q_{ki} <= Qmax_{ki}, \forall_{k,i}$ Minimum: $q_{ki} >= Qmin_{ki}, \forall_{k,i}$

Area energy balance

$$\sum_k \alpha * q_{ki} + \beta * x_{Ai} - x_{iA} = D_i, \forall_i$$

BILLING CODE 6717–01–C

This information is used to determine the generation levels and transmission interchange between control areas that minimizes the sum of generation costs and transmission charges as specified above in the objective function. The key outputs from this algorithm are:

• Power production at each generating unit in each control area.
• Net power interchange between areas.
• Power flowing on each flowgate.
• Marginal cost of power in each area.

Implementing the Basic Model: Data Considerations

In principle, the sample algorithm in the last section could be implemented at a high level of detail, where areas were geographically small, for example, at a level of detail below a utility service territory. This level of detail could approach the level of detail used in detailed power flow and transmission system analysis. In practice, data limitations may make a such a detailed model generally impractical as a screening tool for merger analysis (although in specific cases, more detail can be developed as needed). A reasonable starting point for data considerations is the information currently required to conduct a delivered price test. As discussed above, one would expect many of the sources of information used for computer modeling to be the same as the sources for the non-model application of the delivered price test. Variable generation costs and capacities by area, area demands, interconnections between areas, transmission tariff rates could be the same in both analyses. A computer model would need data on a larger geographic area than a delivered price test for a single destination. However, most of the publicly available sources are not limited to single regions, but provide nationwide coverage. Sometimes this coverage is limited to a particular class of market participants—e.g., Investor-Owned Utilities (IOUs), Municipal utilities, etc. However, it is generally possible to compile nationwide data on the key variables needed in the analysis; consequently, data for the larger geographic areas that may be required for a computer model should be generally available and relatively easy to incorporate in the analysis.

The availability and format of data circumscribe the ways in which key variables in a model can be defined. For parameters that are common to calculations with or without a model the issues of definition are the same in either type of analysis. As an example, consider the question of what areas to use in an analysis. Answers to this question depend on how data are reported geographically, as follows:

• Generator locations can be assigned to specific geographic locations within control areas.
• Tariffs are filed by utility areas (or sometimes for a single holding company such as Southern Company).
• For load scheduling purposes, interconnections are most naturally defined by control area, and Form 714 data are reported on that basis.
• System lambda data are filed on a control area basis.
• Historical loads are most easily derived from the Form 714 filings which are reported on a planning area basis.

These data limitations suggest that areas for modeling purposes might be defined by combining control and planning areas. This definition would permit a modeling analysis to consider different time periods defined on the basis of hourly load data, and to estimate the system lambda corresponding to the load data on a basis that is consistent with the requirements for a delivered price test without a model. Staff seeks comment on this and related issues below.

PTDFs are needed in the model specified in the previous section, but would not be needed if the merger analysis did not use a computer model.[10] Recall that PTDFs relate power exchanges between areas to flows across flowgates. The sample model assumes that the areas in the model are the same ones used to define PTDFs. Although PTDFs are not needed in an analysis that does not use a computer model, they are nevertheless a valuable piece of information for any analysis that needs to examine the implications of loop flow and transmission limits.

Transmission limits are also important data inputs to the computer model. As discussed above, flowgate limits have not yet been defined for the flowgates identified in the NERC data on PTDFs. The best currently available information for estimating limits appears to be OASIS values for Total Transfer Capability (TTC) and Available Transfer Capability (ATC), and transmission capacities reported in various NERC studies and other systems assessments. Since these are the same sources that are needed for a delivered price test analysis, the model does not impose additional data requirements beyond those of the delivered price test. One caveat may be noteworthy, however. A computer model may be more sensitive to data limitations, because the model automatically enforces the transmission system limits on electricity trade. This automatic nature of the computer model is a great benefit if consistent and accurate data are available, because the model can automatically capture the effects of trade across an interconnected electricity grid. However, this characteristic of a computer model can also make results more sensitive to data imperfections than an analysis relying more directly on the analyst's judgment, and suggests that analysts should conduct studies to determine the sensitivity of market simulations results to a range of transmission limits.

Finally, a computer model simulation is a valuable tool for examining the consistency of the data used in the analysis. The model uses all the same information used in the current delivered price analyses for the key parameters: generation costs and capacities, transmission tariffs and limits, and destination market loads. From this information, the computer model simulates generation levels, generation costs, control area prices, and transmission flows between areas. It should be possible to reconcile these simulation results with corresponding reported information. For example, the simulation results (such as control area prices and the costs the marginal generator) should be consistent with reported values for system lambda. Inconsistencies may indicate deficiencies in either the model or the information sources, or both, and large inconsistencies need to be understood before proceeding with the analysis. This is particularly important for system lambda data, since the system lambda data may be used to set the destination market prices. If estimated prices from a simulation are not consistent with system lambda data, the cost information used in a delivered price test (such as the generation costs reported on Form 1) may not be consistent with the destination market prices. Since inconsistencies between estimated and reported values can also arise because of the limitations of the model itself, however, some degree of inconsistency may be inevitable. However, the model would still provide a valuable tool for linking the different sources of information used for the delivered price test and potentially corroborating the system lambda data as a destination market price indicator. As experience is gained in calibrating a model with other sources of information on prices and generation levels, judgments of what destination market prices to use in an analysis should improve.

Applying a Computer Model to Merger Analysis

The discussion has not yet considered the role of a computer model in a delivered price test. It is important to distinguish between the computer model itself and use of the output of the model for merger analysis and the delivered price test. A model simulates generation and power flows in the transmission network based on economic and electrical engineering principles. It is then applied to a particular analysis as defined by a particular procedure. Using a model as a tool in this way does not alter the basic objectives or principles underlying the delivered price test.

To assist the discussion of applying the model to a delivered price test, we divide this section into three parts, as follows:

• A Delivered Price Test Without a Model. The delivered price test is not intended to be applied in a rigid, inflexible manner. Accordingly, staff has tailored the basic steps described here to fit the circumstances in each case.
• Model Outputs Relevant to the Delivered Price Test. This part briefly reviews computer modeling methods and results that are important in the delivered price test. These features are described without reference to technical details of model design and data discussed in previous sections.
• A Delivered Price Test With a Model. A delivered price test with a model will follow the same basic pattern, but details of the procedure will change. This section describes where the model would fit in the context of a typical DPT application.

[10] This is the only data element required for the sample model that would not be needed without it. However, a more complex model might impose additional data requirements. These additional requirements are addressed in the last section of this attachment on questions for a technical conference.

Staff's Framework for a Delivered Price Test Without a Model

The competitive screen analysis focuses on one aspect of merger analysis: whether the merger would significantly increase concentration. The four steps in the competitive screen analysis are:

• Identify relevant products.
• Identify affected customers.
• Identify potential suppliers to affected customers.
• Analyze effect on concentration.

For purposes of comparing a delivered price test with and without a computer model, the key step is the identification of suppliers in the market. This step will be described in detail, but other steps will be also be briefly described for completeness. These descriptions are not meant as a fixed prescription, and we do not mean to imply that there is a single way to conduct a delivered price test. Rather, they describe a set of choices we have found appropriate in previous cases. These choices are guidelines that staff believes can be improved upon as analysis evolves. Their purpose is to distill experience and provide reasonable common ground as guidance, without restricting innovation in future applications.

Identify Relevant Products. Although other products can be appropriate, the relevant product for the delivered price test has typically been short-term energy. Short-term energy has been further differentiated by time period. For most purposes, staff has divided time periods into nine time categories, defined by season and hourly load conditions: winter, summer and spring/fall seasons, with peak, shoulder and off-peak periods being identified for each season. Short-term energy is then analyzed as a separate relevant product for each of the temporal categories.

Identify Affected Customers. Customers have generally been identified based on the facts of each case, the Applicants' filing, and analyses filed by intervenors. The result has been the identification of destination markets with higher probabilities of negative effects. Each destination markets has been analyzed separately for each time period.

Identify Suppliers to Affected Customers. Identifying suppliers to each destination market in each time period involves several choices and related calculations. The identification starts with a decision on how to limit the total group of suppliers included; that is, with how many ''wheels'' away a supplier must be in order to be excluded from consideration. Generally, three wheels has been deemed adequate, but no rigid number of wheels can be determined *a priori,* so the boundaries need to be fitted to the facts of each case. The main remaining components in supplier identification are:

• Competitive price in the destination market.
• Generation costs and capacities.
• Transmission prices and transmission system capability.
• ''Native'' loads.

A general summary how each of these components has been included in the delivered price test is given below.

Competitive price in the destination market. The destination market system lambda provides a default indicator that can be calculated for each of the time periods considered. However, differences in methods underlying the system lambda and well as differences in reporting (such as inclusion or exclusion of purchases) mean that system lambda data should to be compared with other indicators such as published spot prices for consistency. One approach to the problem of uncertainty in any estimate of the competitive price is to analyze concentration for different price levels, in order to determine how sensitive the concentration results are over a plausible range of prices.

Generation costs and capacities. The primary source of information for the capacity and variable cost of generation has been the FERC Form 1 and related forms.[11] These data are available for individual generating plants, but do not provide information on specific units when there are multiple units at a plant. However, it does provide information by prime mover type (*e.g.*, fossil steam, internal combustion) and type of fuel. For purposes of variable cost estimation, this level of detail is a reasonable approximation to unit level information in most cases.

Generation capacity is adjusted for availability, based on estimates of planned and forced outages. Planned and forced outage rates should be based on historical outages, and varied at least by fuel type. If more detailed data are not available on the temporal patterns of outages, outage rates should be applied to represent typical patterns. For example, forced outages are applied equally to all time periods, unless another allocation can be supported. Planned outages are assigned to spring/fall where they would be most expected, except where more explicit scheduling patterns can be supported.

Transmission prices. In general, staff has used firm ceiling rates from open access tariffs. Generally, the maximum applicable hourly rate, in $/MWh, is used. In cases where discounted rates a generally available and posted on OASIS, these discounted rates are used.

Transmission rate structures are undergoing changes, so no single approach is always the best one to use. Where new rate structures have been adopted, the new rate structure should be used. For example, MAPP rates are distance-based, and these current regional rates are used for transmission analysis involving MAPP companies.

In order to determine the transmission costs for a supplier to reach a destination market, it is necessary to trace a ''contract path'' between the supplier and the destination market. The basic information source for identifying the individual companies in these interconnections has been the FERC Form 714. Where there are multiple paths between the supplier and the destination, staff has chosen to assign suppliers to the path with the lowest transmission cost.

[11] For example, the Rural Utility Service Form RUS–12 provides information on generators owned by cooperatives, and the Energy Information Administration Form EIA–412 provides information on municipals.

Transmission capacity. There are two different publicly available sources that can be used to estimate transmission capacity: NERC Regional Reliability Council transmission assessment studies and OASIS reports of Total Transfer Capability (TTC) and Available Transfer Capability (ATC). Staff has used both of these sources, but the specific uses have been based on the strengths and weakness of each source. NERC data provide better supporting detail and can be used for estimation of simultaneous transmission capabilities. However, NERC reports generally report simultaneous transmission capability at the regional or sub-regional level, not at the more detailed geographic area reported on OASIS. OASIS data provide a desirable level of detail (the control area and some sub-control-area detail), but the reporting is not generally on a simultaneous basis and reporting has not fully matured. For example, different OASIS sites report differing TTC/ATC capacities between areas over the same path. Therefore, OASIS data, while detailed, need to be reviewed closely for use in estimating transmission capacity in the delivered price test.

The total generation capacity on a particular path from a supplying area to the destination market is determined by the suppliers assigned to that path. When the available transmission capacity on a path is less than the total generation capacity assigned to the path, it is necessary to allocate capacity to the suppliers comprising the path. The merger policy statement does not endorse any particular method for making this allocation, but the two approaches used by staff are to reduce each supplier's capacity pro rata and to select suppliers in order of generation cost.

Native load estimation. When the measure of capacity used is available economic capacity, an estimate of native load in each area is needed. This estimate is used to reduce the generation capacity available for sales to the destination markets that are being analyzed. For this purpose, FERC Form 714 data on hourly loads can be used to estimate the load in each time period. Because these data are reported on the basis of ''planning areas'', some adjustments to these data are necessary for use in estimating native load by control area.

Analyze effect on concentration. The final step in the analysis is to examine the pre- and post-merger concentrations and compare them to the appropriate thresholds. These concentrations are based on the estimated supplier shares from the supplier identification step, for pre-and post-merger combinations of the following cases:

• Products—short term energy.
• Periods—nine periods by season and load conditions.
• Capacity measure—economic capacity (supplier capacity deliverable at 105% of the competitive price) and available economic capacity (subtracting native load from a supplier's economic capacity).

Model Outputs Relevant to the Delivered Price Test

The steps in supplier identification described above could be conducted using a computer program that uses information on generation costs and capacities, transmission costs and capacities, and other inputs. Such a program would provide a list of suppliers and capacities making up the supply to each market. Without a computer model of the market and transmission grid, these programs cannot take into account certain factors that are important in determining what suppliers can deliver power economically to a particular destination. The two main factors not accounted for are:

- Interactions between suppliers and loads. In a competitive environment, decisions about which suppliers will serve which loads will be driven by opportunity costs, in particular the opportunity cost to suppliers of serving one load rather than another. Because there can be many possible combinations of supplies and loads, some form of computer model could be helpful in estimating such combinations.
- Transmission flows from exchanges of power between areas. Because of the properties of electricity, exchanges of power between areas affect flows throughout the transmission grid. Any approximation of these effects may require a computer model to make the many calculations needed to estimate electric power flows.

Developing and using a computer model involves a number of choices about the structure of the model, the level of detail, the sources of information, and other issues. These issues are discussed elsewhere in this attachment. The main question to raised here is what information the computer program provides to the analyst. Once this question is answered, the discussion turns to the question of how that information can be used in a delivered price test.

For purposes of this discussion, the computer program is assumed to be a simple representation of dispatch of generators to meet a fixed set of loads in a single time period. The program is assumed to simulate the economic dispatch of power over an electric transmission network, by finding the dispatch of generators and exchanges of power between areas that gives the lowest total cost of producing and transmitting the power. Output from this computer program would include generation levels, the quantity of power exchanged between areas, flows on the transmission grid, and the marginal cost of power in each area. Each of these computer model outputs is described briefly below:

- Generation levels. For each generating unit, the computer model estimates the level of output of each generator. It does not estimate which generator sells to which load, but only how much power is generated by each generator when dispatch of that power is at least overall cost.
- Power exchanged. For each pair of interconnected areas, the model gives the net quantity of power exchanged between the areas under economic dispatch.
- Flows on the transmission grid. For each of the transmission facilities represented in the model, the model outputs the quantity of power flowing through that facility. These flows will be limited by any transmission capacity limits that have been input to the model.
- Marginal costs for power. For each area, the model would find the marginal cost of power under economic dispatch. For purposes of this analysis, this cost can be interpreted as the market clearing price for the area.

These model outputs can be used to apply the model in a delivered price analysis. This application is discussed in the next section.

A Delivered Price Test With a Model

One use of a computer model is to use it in a delivered price test analysis. A computer model would be used only in the supplier identification step. The model could be helpful in two parts of this analysis: determining the destination market price and identifying the suppliers that can deliver to each destination market. The role of a computer model in each of these steps is described below:

- Determine destination market price. The default approach to market price determination would still be the system lambda data. However, a computer model could be used here to help corroborate the price used for the destination. As discussed above (p. 14), a computer model could be used to simulate a destination market price for the loads in each time period. This simulated price would not be a substitute for a price estimated from system lambda data, but could be an additional factor in determining how to establish the price and whether to examine a range of market prices rather than a single estimate.
- Identify suppliers to the destination market. A computer model could be used to determine what suppliers could deliver to the destination market. It could simulate the supplier identification procedure of the delivered price test. In the delivered price test, suppliers are considered in the market as long as they can deliver to the destination market at a price less than or equal to a threshold price equal to 5% above the destination market price. A computer model could simulate the same test by considering only the load in the destination market (i.e., assuming all other loads to be zero). Under these conditions, the computer model would be run with increasing destination market demand until the market price reached threshold price. All suppliers running at this price would be identified as supplying the destination market.

In addition to these steps, adjustments to supplier capacity that can be delivered to a destination may be appropriate. One possible adjustment could be to consider other destinations that provide selling opportunities for suppliers and the likelihood that supplier's opportunities may alter their capacity available for delivery to a particular destination market. A computer model is one tool that could be used to assess the effect of these alternatives in a delivered price test. Staff seeks comments on whether these types of adjustment may be appropriate in a delivered price test and how a model could be used for this purpose.

Finally, computer models hold additional potential for application in other areas of the competitive analysis of mergers. In the next section, staff seeks comment on these and other issues.

Issues/Questions for a Technical Conference

Below are questions for comment and perhaps also discussion at a technical conference. Commentors should also raise any other issues they believe need to be considered. In considering these questions or in raising further issues, it is important to specify whether the model is intended primarily as a screening tool or as a detailed and full analytical tool. In the former case the model must therefore strike a balance between detail (with the presumption of greater accuracy and precision) and ease of application within the requirements for a screen.

Questions are listed in five groups: basic model structure, implementing the basic structure, data issues, application to merger analysis and process issues.

Basic Model Structure

The sample model assumes the general form of a mathematical programming problem. Is this the most appropriate technique to simulate economic equilibrium problems in the electricity market? Please be explicit about any proposed alternatives.

The sample model is structured as a linear program. Would another mathematical programming form be better (for example, a quadratic program with piecewise linear supply curves)?

Demands are assumed to be fixed in the sample program, so the demand side of the market is not represented in the sample model. Should demands be made responsive to price? If so, what is the appropriate price elasticity? Should the objective function then be to maximize social welfare (the sum of producer plus consumer surplus)?

The sample model uses distribution factors to estimate power transmission flows. Is this approach adequate? Should Commission staff rely on transmission distribution factors supplied by others (either NERC or another third party) or perform its own transmission system analysis to derive distribution factors for market analysis?

In the sample model, the generator cost functions are represented as a constant variable cost for a unit, even though unit efficiencies vary over the operating range of a generating unit. Is a formulation with a constant variable cost sufficient for purposes of a screening model? Are there alternative formulations of the cost function that can be easily implemented with available information?

How should generating unit availabilities and losses be represented in the model? Could availabilities be treated outside the model, as adjustments to available capacity for each time period studied? Should losses be represented only for transmission flows, or for all generation and transmission, and should different loss factors be supplied for each area? Should losses associated with generation or load within each area be treated differently from losses associated with transmission exchanges or flows across areas? Should losses be transaction based or flow based?

How should generation and transmission reserve requirements be modeled? How should transmission reserve margin (TRM) and capacity benefit margin (CBM) be used?

What additional adjustments are required to account for generation operating reserves, generation planning reserves, or transmission reserves?

Are there other operating conditions that would need to be represented in a model for screening purposes? For example, would a model need to represent operating costs for startup or ramping in order to capture whether particular unit might be available to respond to price increases? Are there any special design considerations for hydropower that need to be incorporated in the model, and how can these best be added?

Alternative Implementation of Basic Model

Is a geographic level of detail corresponding to control areas the best level of detail for purposes of a screening model? If a greater level of detail is necessary, please explain how this detail can be represented with public sources of data or how it can be made part of the filing requirements. Also explain how a more complex analysis with a detailed model could be conducted within the time requirements of a screening analysis. If geographic areas larger than control areas are recommended, please explain how the approach could adequately capture competitive issues required in a merger screen.

The model represents transactions between control areas. Transactions between control areas follow a contract path and pay for each control area transfer between source and destination. As rate structures change and power pools evolve, these rate structures will also change. What design elements should be incorporated to ensure that the model is sufficiently flexible to accommodate these evolving structures?

How should firm sales and contracts be represented in the modeling structure? For example, should generation capacity be reassigned from the selling region to the purchasing region? If capacity is reassigned, which generating units should be associated with the reassignment? Should the transmission capacity be made unavailable for both scheduling and use, that is, should it be assumed that the purchaser is obligated to use the power rather than resell it, so capacity will be used and not available for short-term trading in the model?

The model can simulate a market (minimize costs) over any arbitrary area for which data are available. Should the overall area be broad, for example, the Eastern Interconnection, or should it be limited to a smaller area surrounding the parties to a merger? Discuss how trade with areas outside the area represented in the model should be analyzed and incorporated in the model.

Should different modeling structures be used to simulate the different characteristics of power trading and power flows for different regions? For example, is the sample model considered equally applicable to the analysis of the Eastern Interconnection and WSCC? If not, what key differences between regions should be reflected in the structure of the model, and how should they be represented?

Data Issues

Are there alternatives to using FERC Form 1 data (and data from related public sources) for generator costs and capacities that provide comparable geographic and company coverage?

What are the best data for estimating the fuel cost component of variable cost? Should historical costs, such as those reported on Form 1 be used? Or should other estimates, such as spot prices, be used? If a single heat rate is used for each unit to convert fuel costs to a cost per unit of electricity, should that heat rate be taken from Form 1? Or are other heat rates, such as those filed by unit on the Energy Information Administration Form 860, a better estimator of the cost of power from the unit?

Should variable cost include non-fuel operating and maintenance costs? What components should make up non-fuel operating costs? Can these costs be estimated from Form 1 data with sufficient accuracy for a model? If they can, what methods should be used for estimating these costs from Form 1 data? If they cannot be estimated from Form 1 costs, what sources of information should be used in their estimation?

Should NERC PTDFs and flowgate limits (if available) be used? What are the strengths and weaknesses of using the NERC PTDFs and flowgate limits? If flowgate limits associated with NERC-calculated PTDFs are available, can they be used in the way they are represented in the sample model discussed in this attachment? If they should be incorporated in a model using an approach that is different from the one described in this attachment, what should that approach be?

If NERC flowgate limits are unavailable, is the approach of using PTDFs and flowgate limits to represent the physical network still practical? If the PTDF approach is practical in the absence of flowgate limits provided from NERC, how should other sources of transmission limit information (such as OASIS TTC or ATC data or system reliability studies) be used to estimate flowgate limits? If the PTDF approach is not practical, how should actual power flows and transmission limits be modeled?

Environmental factors can influence the variable cost of operating plants. For example, the variable cost of operating coal plants is affected by the cost of SO_2 allowances, and environmental programs in California and the Northeast could have a significant impact on costs. Are these costs adequately captured by publicly available sources, such as the reported costs on Form 1, or do they require separate cost estimation?

Application to Merger Analysis

Can the model be straightforwardly applied to simulate the supplier identification step of a delivered price test that is consistent with a delivered price test performed without a model? First, consider the delivered price test as it is described and applied currently, without adjustments to supplier capacity. Then consider how a model might be used to adjust supplier capacity for the presence of loads at other destination markets, and how such adjustment could be made in a manner consistent with the purposes of the delivered price test.

In addition to using a model in a delivered price analysis, what are the other areas of market definition or of the analysis of the competitive effects of mergers where a computer model could be used? Comments may address the general use of computer models in antitrust analysis, such as their use in a hypothetical monopolist test or their use in simulating dominant firm behavior. However, comments should address how these applications might function as a screening tool and in the Policy Statement. In your comments, specify what these areas of application are and what benefits are provided by using the model, how the model would be used in the analysis (in as much detail as possible), and how use of the model can be made consistent with the practical constraints of time and resources available in the screening context.

Process of Model Development and Maintenance

The staff believes that a computer model can be a feasible part of a horizontal screen, and will aid the analysis. The model may also have the potential to expedite the analysis by providing agreed-upon standard methods that can be applied in merger analysis. Are these beliefs sound, or are there limitations in principle or practice that make the use of models infeasible as part of a horizontal merger screen?

What should the Commission require with respect to computer modeling in merger analysis? Should it endorse a specific computer model, a particular modeling approach (such as an economic dispatch model), or only a general framework? Or should it only seek to provide guidance on how a model should be used if applicants choose to include one in their application?

Are there existing models that meet the requirements for use in a horizontal screen? Explain how any candidate model could be used by staff, applicants and/or intervenors in the context of a merger application? Address issues of technical adequacy, practical issues such as complexity and ease of use, and procedural issues such as the proprietary nature of third-party commercial software products. If there are other existing models, should the Commission staff acquire a existing model, or should Commission staff develop a model for its own use and the use of applicants and intervenors?

If the Commission staff were to develop a model rather than acquire an already existing model, what development approach should be taken? Should the model be developed by Commission staff based on technical discussion and input from industry, by industry groups with Commission oversight, or some other way? If the Commission adopted the approach of issuing guidelines only, but not developing a single model for general use by staff and applicants, would independent development of models by others provide models of sufficient quality and standardization for merger analysis purposes?

How should a model be tested prior to use in specific merger cases? If a model has been used in other contexts, under what conditions should that use be regarded as sufficient to validate its use as part of a horizontal screen analysis? If the Commission staff were to develop or adopt a new model for use in merger analysis, how should it be tested to ensure that the design criteria have been met?

How should a model and associated databases be maintained and updated? What process should be followed to identify needed modifications to the model and create new versions of the computer code? Should a fixed set of data inputs be identified, in order to avoid this potential difficulty and provide consistent a starting point for analysis (assuming applicants can file additional data for further analyses if they choose)? As an alternative, should applicants be permitted to substitute the most recent data from the same sources even if these data have not previously tested in the model? Or should a standard set of model inputs be maintained and updated as a group? If a standard set of inputs is maintained, should Commission staff be directly responsible for the maintenance of these data or can this responsibility be carried out by third parties?

[FR Doc. 98–10687 Filed 4–23–98; 8:45 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[ER–FRL–5491–2]

Environmental Impact Statements and Regulations; Availability of EPA Comments

Availability of EPA comments prepared April 06, 1998 Through April 10, 1998 pursuant to the Environmental Review Process (ERP), under Section 309 of the Clean Air Act and Section 102(2)(c) of the National Environmental Policy Act as amended. Requests for copies of EPA comments can be directed to the OFFICE OF FEDERAL ACTIVITIES AT (202) 564–7167.

An explanation of the ratings assigned to draft environmental impact statements (EISs) was published in FR dated April 11, 1998 (62 FR 16154).

Draft EISs

ERP No. D–AFS–L67036–OR Rating EO2, Nicore Mining Project, Implementation, Plan-of-Operations, Mining of Four Sites, Road Construction, Reconstruction, Hauling and Stockpiling of Ore, Rough and Ready Creek Watershed, Illinois Valley Ranger District, Siskiyou National Forest, Medford District, Josephine County, OR.

Summary: EPA expressed environmental objections based on lack of information or alternatives, the potential cumulative impacts of additional mine patents in the area, a failure to meet the intent of the Aquatic Conservation Strategy in the President's Forest Plan, a lack of a detailed reclamation plan, a lack of a monitoring plan and potential sediment impacts to Rough and Ready Creek.

ERP No. DR–BLM–K67040–CA Rating EO2, Imperial Project, Open-Pit Precious Metal Mining Operation Utilizing Heap Leach Processes, Plan of Operations, Right-of-Way, Conditional Use Permit, US COE Permit and Reclamation Plan Approvals, El Centro Resource Area, California Area District, Imperial County, CA.

Summary: EPA expressed environmental objections based on potential significant environmental degradation to waters of the United States, and requested additional alternatives analyses and data. EPA also expressed serious concerns that the project could interfere with basic rights of Native Americans to practice their religious beliefs, and asked BLM to provide information on its policies, guidelines and standards with respect to this issue.

Final EISs

ERP No. F–AFS–J65251–CO Arapaho and Roosevelt National Forests and Pawnee National Grassland, Implementation, Land and Resource Management Plan, Boulder, Clear Creek, Gilpin, Grand, Larimer and Weld Counties, CO.

Summary: EPA review finds the alternative selected in the FEIS to be responsive to the Forests and Grasslands need and to environmental considerations for Plan Implementation.

ERP No. F–AFS–J65276–CO Dome Peak Timber Sale, Timber Harvesting and Road Construction, White River National Forest, Eagle Ranger District, Glenwood Spring, Eagle and Garfield Counties, CO.

Summary: EPA review has not identified any potential environmental impacts.

ERP No. F–COE–G39031–LA Mississippi River—Gulf Outlet (MRGO) New Lock and Connecting Channels Replacement and Construction for Connection to the Mississippi River, Implementation, Orleans and St. Bernard Parishes, LA.

Summary: EPA expressed lack of objections to the recommend plan and have no other comments to offer.

ERP No. F–NPS–K61144–HI Ala Kahakai ''Trail By the Sea'' National Trail Study, Implementation, Hawaii Island, Hawaii County, HI.

Summary: Review of the Final was not deemed necessary. No formal comment letter was sent to the preparing agency.

ERP No. FS–NOA–K90025–CA Monterey Bay National Marine Sanctuary Management Plan, Updated Information, To Amend the Designation Document and Regulations to Allow Jade Collecting in the Sanctuary, San Mateo, Santa Cruz and Monterey Counties, CA.

Summary: Review of the Final EIS was not deemed necessary. No formal comment letter was sent to the preparing agency.

Dated: April 21, 1998.

William D. Dickerson,

Director, NEPA Compliance Division, Office of Federal Activities.

[FR Doc. 98–10990 Filed 4–23–98; 8:45 am]

BILLING CODE 6560–50–U

ENVIRONMENTAL PROTECTION AGENCY

[ER–FRL–5491–1]

Environmental Impact Statements; Notice of Availability

Responsible Agency: Office of Federal Activities, General Information (202) 564–7167 OR (202) 564–7153.

Weekly receipt of Environmental Impact Statements Filed April 13, 1998 Through April 17, 1998 Pursuant to 40 CFR 1506.9.

EIS No. 980122, Draft Supplement, COE, DE, Delaware Coast from Cape Henlopen to Fenwick Island Feasbility Study and Bethany Beach and South Bethany Interim Feasbility Study, Additional Information, Storm Damage Reduction and Construct a Protective Berm and Dune, Sussex County, DE, Due: June 08, 1998, Contact: Steve Allen (215) 656–6559.

EIS No. 980128, Draft EIS, BLM, WY, Newcastle Resource Management Plan, Implementation, Updated Information, Evaluates Alternatives for the Use Public and Federal Lands and Resources in Portions of Wyoming, Crook, Niobrara and Weston Counties, WY, Due: July 23, 1998, Contact: Floyd Ewing (307) 746–4453.

EIS No. 980129, Final EIS, FHW, TN, I–40 Reconstruction, I–40/I–240 Directional (Midtown) Interchange to TN–300 Interchange, Funding and Possible COE 404 Permit, Shelby County, TN, Due: May 26, 1998, Contact: James E. Scapellato (615) 736–5394.

EIS No. 980130, Final EIS, AFS, CO, South Quartzite Timber Sale, Timber Harvesting and Road Construction, White River National Forest, Rifle Ranger District, Grizzly Creek Rare II Area, Garfield County, CO, Due: May 26, 1998, Contact: David T. Van Norman (970) 927–5715.

EIS No. 980131, Final EIS, AFS, CA, Emigrant Wilderness Management