THE NEMS CONFERENCE

ELECTRICITY PLANNING PANEL

February 1, 1993 - 3:15 pm

PANELISTS:

J. Alan Beamon, Moderator
Jeffrey Jones, Presenter
Martin Baughman, Reviewer
John Hughes, Reviewer
Howard Mueller, Jr., Reviewer

AUDIENCE PARTICIPANTS:

Steve Mack
Jack Butler
Virginia Sulzberger
Steve Bernow
Keith Laughlin
Paul Altberger

EIA

PROCEEDINGS

MR. BEAMON: Well, I want to welcome you all to the last session of the day and I think we'd better get moving so we don't keep everybody here too late. I won't be too upset if you all walk out to catch your car pools and don't hit me with a few questions at the end. So, don't feel too bashful.

We're here to talk about electricity capacity planning. Essentially, Jeff is going to go through the electricity capacity planning methodology that we've proposed. I'm going to talk a little bit after that on how we're going to deal with some of the issues related to demand side management and new technology penetration.

For those of you who don't know me, I'm Alan Beamon. I'm the team leader of the Electric Utility and Non-Utility Analysis Team and I've been at EIA since 1984. Prior to that I was at the Bureau of Labor Statistics. Since then I've worked on so many electricity analyses I can't recall them all.

We're going to try to keep this on schedule, ending at 5:15. If anybody has any questions after that, we'll certainly take them and we'll try to respond to them later.

At this time, I'll introduce our main speaker to you. He's Jeff Jones. He's the lead analyst on the Electric Utility and Non-Utility Analysis Team and he's primarily responsible for designing the capacity planning subcomponent. As I said, he's going to talk about the capacity planning methodology and then I'm going to give a brief discussion on how we're going to treat DSM.

Jeff?

MR. JONES: Good afternoon. I'd like to welcome you here today. As Alan said, I'm going to be explaining the capacity planning module to you today and within the context of the NEMS development, I think one of the words I hear most often used is ambitious. That's probably a fairly accurate word. I think it also applies to the electricity planning component. We've found many of the suggestions we've already received from various reviewers of the component design reports, as well as other briefings that we've done, to be very useful and we would welcome any other suggestions that you might have on how we might improve the representation that we're trying to impose.

We're especially fond of questions that have answers along with them, so don't be afraid of supplying those as well.

The first slide is an overview of the Electricity Market Module. If you attended the earlier sessions today where Mary Hutzler presented the NEMS overview, you saw this particular slide. And if you attend any of the subsequent briefings on the Electricity Market Module, you'll see it again. So, you'll probably become very familiar with it by the time you're through here.

The three boxes on top of the chart which correspond to various submodules within

Electricity Capacity Planning
in the
National Energy Modeling System

584

Jeffrey Jones
Energy Information Administration

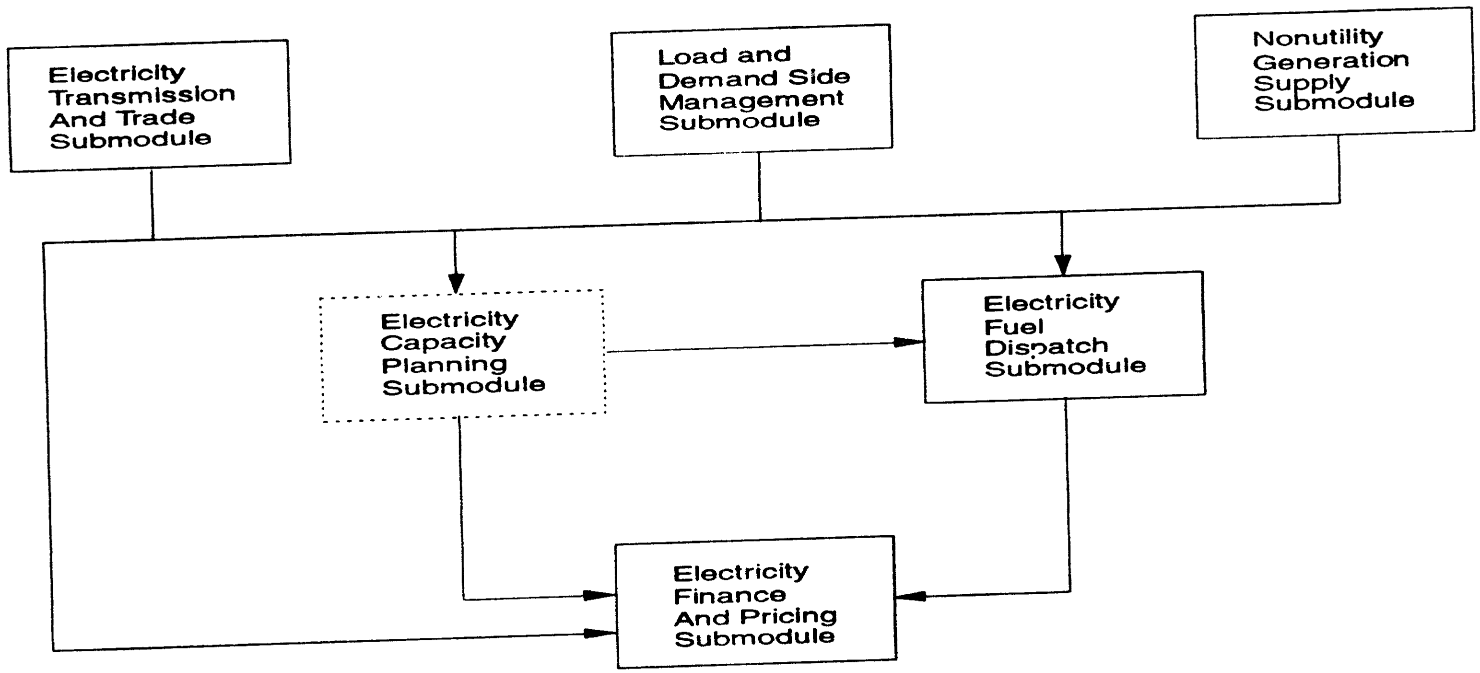
EIA

February 1, 1993

OIAF 1/93

Wordchart 2

INFORMATION FLOW WITHIN THE ELECTRICITY MARKET MODULE



the Electricity Market Module essentially are feeding information to the lower three components. The Electricity Transmission and Trade Submodule will feed information to construct supply curves for power purchases. The Load and Demand Side Management Submodule will provide the Capacity Planning Submodule with cost and performance data which will be used to characterize DSM programs and how they might contribute to the need for capacity. It will also develop information on loads for electric power demand and provide the characterization of electric power demand for use in both the Capacity Planning Submodule as well as the Fuel Dispatch Submodule.

The Non-Utility Generation Supply Module will also supply cost and performance data for non-utility suppliers, excluding cogenerators. Primarily, this includes the independent power producers as well as the new class, exempt wholesale generators, that was created in the Energy Policy Act.

The primary functions of the capacity planning module are to determine changes in capacity that are required due to growth and demand for electricity, as well as to achieve compliance with environmental regulations such as the Clean Air Act Amendments of 1990. Those are the major outputs that it passes to the electricity fuel dispatch module. It will pass the available capacity in a particular year, which is a function of the existing capacity, the retirements as well as any capacity expansion decisions that result from the ECP. It will also pass information about any pollution control equipment that's been installed as a result of compliance with any environmental regulations such as the Clean Air Act.

For the Electricity Financing and Pricing Submodule, the Capacity Planning Submodule will pass information on capital expenditures on new generation equipment as well as pollution control equipment which will be used to compute the price of electricity.

I think one of the reasons the Capacity Planning Submodule is probably the most complex and challenging component that we're going to be dealing with is that there's such a wide variety of issues that it has to tackle. This particular list in front of you is by no means intended as a comprehensive list, nor is it in any order of priority, because you each could probably put them in your own priority. But it does, hopefully, highlight some of the major issues that we're intending to deal with within the Capacity Planning Submodule.

The first one is technology choice and that obviously deals with what types of plants and what fuel choice decisions will be made to meet demand growth in the future. Along with that, we're also expanding our representation of renewable technologies. If you attended some of the prior sessions, I'm sure you've been told by now that in our previous modeling efforts to date, we essentially treated renewables as an exogenous component and we simply determined the remaining picture with the contributions from renewable supplies decremented from the total requirement. We're making a rather extended effort to enhance our representation of renewable technologies, particularly intermittent energy sources which are a little bit more difficult to deal with, and to actually bring it in so that we have an integrated decision process.

The Capacity Planning Submodule also has to deal with the ownership issues with respect to just who is going to be building plants in the future, whether it's traditionally as

KEY ISSUES

- Technology Choice
- Renewable Technologies (Intermittents)
- Ownership Type (Utilities/Exempt Wholesale Generators)
- Environmental Regulations
- Demand-Side Management (DSM)
- Cost Estimates for New Technologies

OIAF 2/93

the electric utilities have, or the recent players, the independent power producers and again the new class of generators, the exempt wholesale generators, that was created by the Energy Policy Act.

Another major function of the planning component is determining compliance strategies with environmental regulations. As I've mentioned before, that includes the Clean Air Act Amendments of 1990, looking at capital decisions that are required to reduce emissions in compliance with that act. It also is not limited to that act, but it must be flexible enough to deal with other potential sources of regulations such as limits on carbon emissions as well as some of the various energy policies that are being bandied about town right now. It seems to be a rather hot topic around the city.

Of course there's demand side management. Again in our previous modeling efforts we essentially treated demand side management as an exogenous topic. We determined contributions that would be met by demand side management programs outside the model and then simply determine the supply side options within the model. Within the NEMS we're trying to compete the two directly so that it can more closely represent integrated resource planning.

Finally, another topic which tends to come up is in relation to new technologies. Basically most of my discussion is going to center around the midterm modeling capability that we're developing and that's through 2015. Even within that time frame, it's quite likely or even expected that new or emerging technologies will become available during that time frame and we'll have to evaluate them. There are always questions involved with whether you characterize those technologies from both a cost and a performance standpoint, given that there may be little or no data on those technologies.

With respect to technology choice, we intend to represent specific technologies as opposed to just generic fuel type technologies. Again, we will represent the actual technologies that would be penetrating. Both conventional and advanced fossil fuel, renewable, and nuclear technologies, as I mentioned before, will be represented in the model so that they will directly compete. We will try to characterize some of the uncertainty that will be associated with that and just how that will play with some of the more conventional sources that have typically supplied most of the electricity.

Again, unlike our current modeling capability, we're going to compete the renewable technologies along with the non-renewable technologies. We'll be competing dispatchable technologies along with the intermittents. Again, there are some special problems that that poses, but I'll try to explain some of that a little bit later.

We're also going to try to characterize both the competition between foreign and domestic supplies for electricity by incorporating supply curves from Canada and Mexico.

With respect to intermittent renewables, unlike dispatchable technologies, which except for unscheduled outages and things like that basically can be utilized at any time of the year, there may be questions of availability for some of the intermittent technologies. For solar, if there's no backup or no storage technology, obviously you need the sun to be

TECHNOLOGY CHOICE

- Represent Specific Technologies

- Compete Both Conventional and Advanced Technologies

- Compete Renewable Technologies With Other Generating Options

- Utilize Supply Curves to Represent International Supply Options (Canada and Mexico)

INTERMITTENT RENEWABLES

- Account for Variations in Production Capability By Season or Time of Day

- Determine Contribution to Total Capacity Requirement Based on Availability of Energy Source at Time of Peak Demand

- Evaluate Intermittent Technologies with No Capacity Credit on the Basis of Fuel Savings shining. With wind you need the wind to be blowing. There are certain seasonal and daily and periodic variations in those supplies that we're going to have to capture.

Along with the energy content of the intermittent renewables, we also have to try to capture what their impact is going to be on reliability requirements. In this case, we're looking at the definition of reliability as being the ability to meet the peak demand. Therefore, the representation of reliability for these intermittent technologies would be their availability to produce electricity at the time of peak demand. We're going to use the concept of a capacity credit. At this time that's what we're looking at to represent that. For example, if the peak demand were to happen overnight in the dead of winter, then solar technology without a backup or without storage might get a zero capacity credit, whereas if it happened to be a summer peaking location where the peak demand occurred because of air conditioning demands in the middle of summer, then solar might get a full capacity credit.

So, we're going to be evaluating each one of these technologies and look at just what capacity credit would be assigned to them and evaluate them in the context of how they contribute to the total need for capacity.

One thing I want to make clear though is if an intermittent technology receives no capacity credit, that is not necessarily going to preclude it from being built. It will also evaluate whether that particular technology might penetrate on the basis of the fuel savings that would occur by displacing another potentially high variable cost technology and therefore there still will be opportunities and markets for intermittents with no capacity credit to penetrate.

With respect to ownership type, the cogenerators will not be dealt with within the electric utility module. The contributions from cogenerators will be determined in the specific end-use demand component. It will then be passed to the electric utility module and used as a decrement to the required supply. The electric utility module will then determine the appropriate supply-side and demand-side options that are necessary to meet what's remaining. The required capacity additions, as I had mentioned earlier, will be determined by ownership type with respect to both utilities and the exempt wholesale generators.

Another major component of the model which is a departure from our current modeling efforts, is that we will have an endogenous representation of environmental regulations. Obviously the first and foremost with respect to that is the Clean Air Act Amendments of 1990. The Electricity Capacity Planning Submodule will make the "planning decisions" that are required for compliance. Examples of that are retrofitting existing units with flue gas sulfurization equipment. In order to do that, it must contain a representation of dispatching as well. So, the actual modeling structure contains both planning and dispatching options so that it can examine the tradeoff between capital and operating costs in order to make its decisions.

It will also look at intertemporal decisions related to the Clean Air Act Amendments. That's primarily banking of emissions, where a utility may over comply in a given year, and, as a result, incur greater expenses, so that it can under comply in some subsequent

OWNERSHIP TYPE

- Cogenerators Determined in Appropriate End-Use Demand Module

- Total Capability Requirement Adjusted to Account for Contributions from Cogenerators

- Required Capacity Additions Determined for Electric Utilities and Exempt Wholesale Generators (EWGs)

Environmental Regulations

- Investment Decisions (e.g. Scrubbing) for Compliance With Clean Air Act Amendments of 1990

- Intertemporal Decisions (e.g. Banking) for Compliance With Clean Air Amendments of 1990

- Impacts of Alternative Environmental Regulations
  (e.g. cap on carbon emissions)

- Impacts of Environmental Regulations on Capacity Expansion Decisions
  (e.g. Technology Choice)

year.

The model also must be flexible enough to consider alternative environmental regulations such as a cap on carbon emissions and it must also capture not only decisions on existing equipment but what the impacts of environmental regulations are going to be on capacity expansion decisions. For instance, the Clear Air Act Amendment has a system of allowances allocated for SO_2 emissions and a new plant is not allocated any allowances, which means in order for that plant to emit SO_2 it has to come up with an allowance, either purchase one or other plants owned by the utilities have to over comply to free up the allowances. There will obviously be a cost associated with that. That's going to be a factor that's going to be in favor of plant types that use lower sulfur fuels or demand side management programs where that will be either less of a problem or not a problem at all.

Now I'm going to get a little bit into the proposed methodology that we used. To represent the demand for electricity, we're starting out from the hourly load data that's basically in chronological order and will be used in the Load and Demand-Side Management Submodule to create a load duration curve. The load duration curve basically lost all representation of the chronological order of demands. We are going to seek to maintain some of the time dependent characteristics and this is particularly important in order to represent DSM. It's important to represent intermittents and it's also important to represent seasonal fluctuations in demand.

We're planning on using a 10-year rolling planning horizon in which we're going to examine what planning decisions are going to be implemented over the next 10 years and we're going to do this on the basis of multi-period optimization in terms of what's best for the entire 10-year period as opposed to what would result in the least cost option for a single year within that period. And again, it also will allow us to examine some of the intertemporal questions that are necessary in the planning component.

The central integrating structure of the Electricity Capacity Planning Submodule itself is a linear programming, or an LP, model. Within this model itself, it will compete the individual technologies, both the conventional and the advanced technologies. It will also include specific limits on emissions such as SO_2, carbon, whatever happens to emerge, but the model itself will contain explicit representations of both the capacity expansion and the environmental decisions.

The LP model does some things well and there are other things that it doesn't do well. One of the things that it doesn't do well is it tends to go towards all-or-nothing decisions in some cases. If you have basically no limit on a particular option, it will tend toward choosing as much of that particular option as it can possibly get. And so one of the things that we're planning on doing to help combat that problem is to augment the LP model with a market-sharing algorithm to adjust some of the all-or-nothing decisions, and it's in this market-sharing algorithm that we're also going to deal with the ownership issue questions.

Within the load duration curve itself, the loads are going to be classified according to seasonal, daily, and time of day categories. We've done some considerable amount of

Proposed Methodology

- Load Duration Curve
  - Maintain time-dependent load characteristics
- Ten-Year "Rolling" Planning Horizon
  - Permits multiperiod optimization
  - Considers intertemporal decisions
- Linear Programming (LP) Structure
  - Competes specific technologies, both conventional and advanced
  - Contains explicit representation of emissions limits
- Market-Sharing Algorithm
  - Adjusts "all-or-nothing" decisions from LP model
  - Determines Ownership Shares

Load Duration Curve

- Define Load Categories
  - Four Seasons
  - Weekday/Weekend
  - Daytime/Evening/Nighttime
- Include Peak/Near-Peak Segments
- Combine Load Data for Several Historical Years

investigation on trying to determine just what the best breakout of loads are going to be to represent the various topics that we need to represent. Right now we're keying on four seasons which are pretty much the standard four seasons, segmenting the loads by weekday and weekend and then having daytime, evening, and nighttime load categories where there are obvious mappings with DSM and intermittent technologies.

As well as that, we're going to include peak and near-peak segments as well, and that will give us a more accurate representation of the total capacity requirement which, if you don't separate out a segment specifically for the peak, then you tend to lose some of that.

And another thing that we're doing differently from our current modeling is we're going to combine load data for several years. Previously we tended to average it and one of the consequences of that is you tend to smooth out some of the extreme loads and your peaks get lower and your minimum demands get higher. By doing this, we're hoping to capture much more of the fluctuations and the extreme demands that occur.

There are several reasons behind why we chose the 10-year planning horizon. The length of horizon is something that we have some degree of latitude in. The options range from using a single year to optimizing the decisions over the entire 20 to 25 year planning horizon. There are obvious tradeoffs in going between the two extremes. The more years you take, you tend to probably get a more accurate result, but there's also a tremendous computational burden associated with doing that many years.

So we've been focusing on a ten-year horizon and that seems to conform reasonably well with the way the industry looks at projections. The capacity planning data and retirement data reported to EIA are for a 10-year period. If you look at the NERC reliability projections, they're also for a 10-year period. And we also felt it's obviously necessary to cover all of the potential options you might have and I would think at this point, if a particular option takes more than 10 years, it's not going to represent much of a feasible option for meeting future supplies.

The one additional consequence of using a multi-year representation is it does allow us to examine the intertemporal issues as well.

Just to give you a quick overview of the LP structure, as I said before, the LP structure is going to represent both the planning and the dispatching options that are necessary to meet the demand for electricity and comply with environmental regulations. One of the primary requirements of the model is that in each of the load segments that I described earlier the capacity and the energy requirements are going to have to be satisfied through a combination of existing sources, new sources, as well as demand-side options.

The dispatchable capacity options such as your traditional fossil-fired plants would be candidates to satisfy the energy and capacity requirements in any particular segment, whereas some specific DSM programs as well as intermittent technologies would only be able to satisfy the needs in certain segments where their availability would coincide.

Ten-Year "Rolling" Planning Horizon

- Represents Reporting Period for Utility Capacity Expansion Plans as Reported on Form EIA-860

- Corresponds to Evaluation Period Reported in the NERC's Electricity Supply & Demand Projections

- Allows Sufficient Time to Cover Longest Leadtime Options

- Permits Examination of Intertemporal Issues

Linear Programming Structure

- Satisfy Capacity and Energy Requirements in Each Load Segment
- Utilize Dispatchable Technologies in Any Load Segment
- Limit Intermittent Technologies and DSM Programs to Specific Segments
- Meet Minimum Reliability Requirements
- Allow Full, Partial, or No Capacity Credit
- Impose Explicit Limit on Emissions Such as SO2

OIAF 2/93

Market-Sharing Algorithm

- Measure Competitiveness of Technologies Using Reduced Costs Generated by the LP Model.
- Reconsider Technologies Whose Costs Fall Within a Given Competitive Range.
- Reallocate Capacity Expansion Decisions Among Competitive Technologies.
- Allocate Capacity Expansion Decisions Among Ownership Types.

One of the major requirements of the model is that the minimum reliability requirements have to be met. As I said before, each of the technologies will be characterized by a capacity credit ranging from zero to one and there will be an explicit limit on emissions such as sulfur dioxide along with the capability to add additional constraints if they do emerge or if certain policy studies require looking at those issues.

We can also add regional constraints in addition to the national constraints if that's necessary and that could arise with respect to the Clean Air Act if certain disequilibrium conditions arrive where certain states basically don't allow trading or require you to use some of their own fuels and things like that. That may override some of the national level constraints as specified in the bill.

The market-sharing algorithm will basically be a follow-on from the linear programming model. For those of you who aren't really familiar with LP models, I don't plan to get very technical, but I do have to explain one term a little bit, the reduced cost.

One of the outputs that can be generated from the model is known as a reduced cost. For those options that do not penetrate into or are not selected by the LP model, the model generates a reduced cost which essentially indicates how much the cost for that particular option would have to be lowered in order for it to be selective. So we're basically going to look at those reduced costs and try to get a sense of which technologies were reasonably competitive and may have penetrated the solution if the costs were a little bit different.

In the LP model itself, we're basically using a point estimate for the cost and typically that point is the expected value. Given that a lot of this data is probably characterized by distribution around that expected value, it's quite likely that some of the particular technology would penetrate even if its expected value was higher than another technology.

So, based on the reduced cost, we're going to look at various procedures for reallocating the capacity expansion decisions to other technologies whose reduced cost falls in a fairly competitive range. We haven't defined what a competitive range is yet. That's something we're going to have to look into.

One of the other attributes of the market-sharing algorithm is we're going to look at the respective cost structures of utilities and non-utilities and attempt to allocate the capacity expansion decisions among the ownership types within this framework as well.

Now Alan is going to talk a little bit on DSM.

MR. BEAMON: Perhaps one of the things we should have done is renamed this submodule, because it's not really capacity planning. It's resource planning, because we're going to try to take into account both the supply-side options and the demand-side options. The selections will be carried out in the Capacity Planning Submodule. What we're referring to as the Load and Demand-Side Management Submodule will be preparing these options and passing this information for possible selection or competition with supply side options in the Capacity Planning Submodule.

What I want to do here is just talk about how the LDSM, as we refer to it, is going to operate. The LDSM will map Census level demand data from the demand models into the NERC region demand data that we'll be operating with in the electricity models. It will have to translate the annual demand levels into system load shapes for use in the capacity expansion and the dispatching algorithms. We're also planning to represent the impacts of intermittent generating technologies on system load shapes within the LDSM.

The primary and most important function, what I'm going to spend most of my time on here, is that the LDSM will deal with the screening of DSM options for later selection and evaluation in the capacity planning algorithm.

This slide just gives you a little bit of a flow chart of all of these options. Again, the NEMS demand models operate at the Census division level and they also operate at annual demand levels, so that information will be passed to the LDSM which will convert this information into hourly load forecasts at the NERC region and subregion level to be used in the Electricity Market Module.

We are dealing with intermittent technologies in the LDSM, because some of the intermittent technologies such as wind or solar, as Jeff mentioned, have a particular resource availability that often will define their generation load shapes. We will map this resource availability into this load shape information so that it can be evaluated in the capacity planing submodule.

I'm going to talk a little bit now about the steps that are going to go through the DSM screening process in the LDSM.

The first thing that the LDSM will do is develop all of the possible DSM options available for consideration. Now this will be done in concert with end-use technology databases that are shared between the LDSM and the various NEMS end-use demand models. In other words, these databases will contain all of the various technologies plus their cost and performance characteristics for each end use.

In using this information, the LDSM will develop its list of options. For each one it will calculate the incremental impact, in other words the impact of going from a base or standard unit to a more efficient unit. It will then estimate the payback of a program of that nature using electricity rate information and the difference in capital costs and operating costs of the more efficient technology. It will estimate the simple payback in years that that program would generate.

Now, to develop market penetration algorithms we've assumed that we're going to develop a payback scheme for rebates at a two year payback, but that's an option we can reconsider. We're going to use the payback acceptance curve approach to estimate the market penetration of these different options.

This next slide shows you an illustration of the payback acceptance approach. As the slide shows, as you get to a quicker and quicker payback you would normally expect a higher final market penetration. At this point, this methodology is a little bit out of sync

DSM Option Selection

- DSM options will be developed in the Load and Demand Side Management Submodule (LDSM) and competed against other resource options in the Electricity Capacity Planning (ECP)

- LDSM functions include:

  Mapping of CENSUS demand data into NERC region data, and vice-a-versa

  Translation of total electricity consumption forecasts (by end-use) into system load shapes

  Representation of the impacts of intermittent generating technologies on system load shapes

  Development and screening of utility DSM programs for potential inclusion in future utility capacity expansion plans

LDSM Tasks

Electric Demand Regional Mapping

↓

System Load Shape Development

↓

Intermittent Technology
Load Shape Development

↓

DSM Screening

↓

ECP and EFD Submodules

↓

Disaggregation of DSM Programs

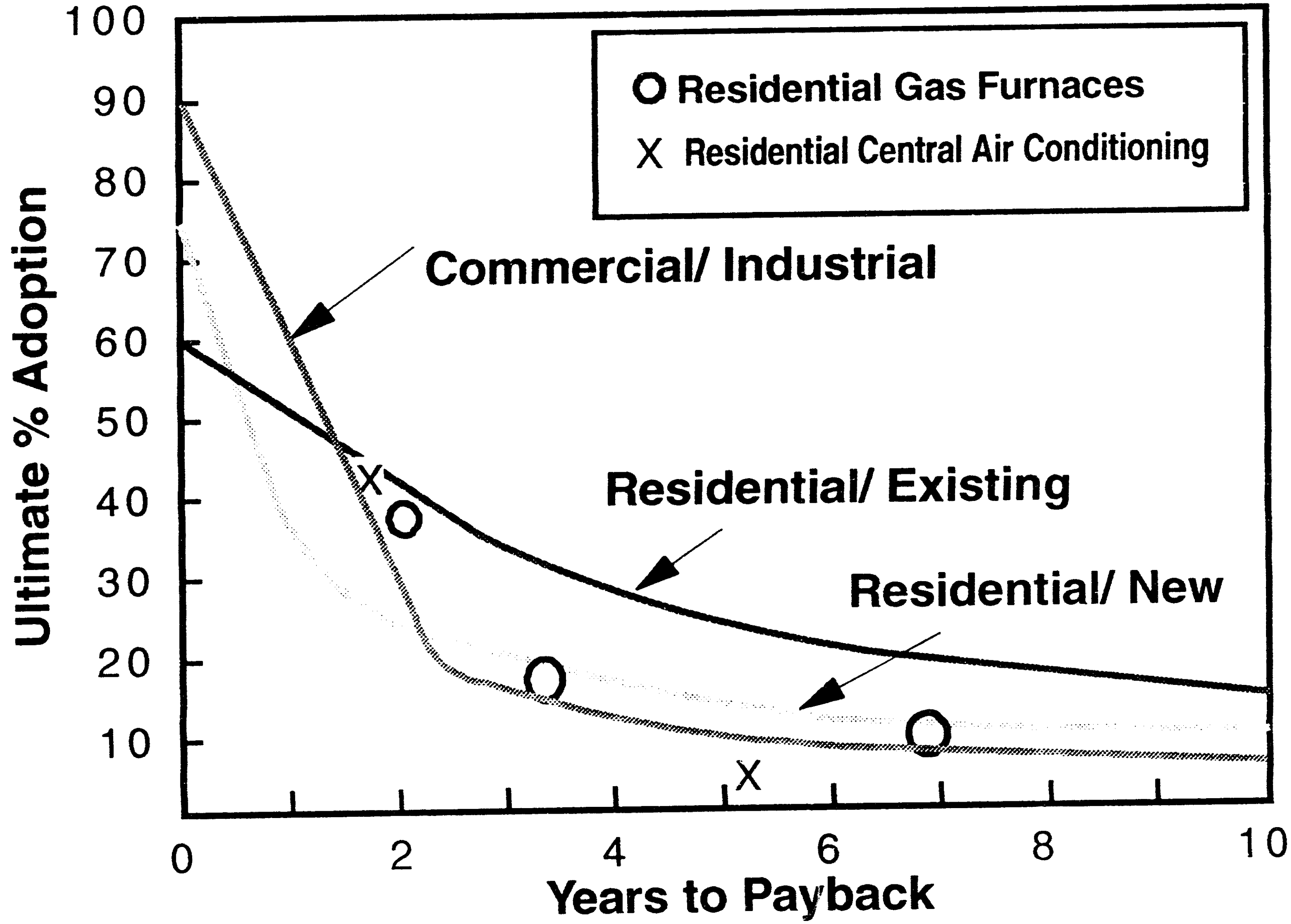
↓

NEMS Demand Modules

DSM Screening

- DSM option set development
- Incremental impact estimation
- Payback estimation
- Market penetration estimation

Payback Acceptance Approach



with what some of the demand modules are doing and we're going to be working on that to make sure that we're not dealing with these issues inconsistently.

Once this information has been developed, each program will undergo a cost effectiveness test. We're going to use as a test for this the California Total Resource Cost Test. I want to emphasize here that this is just a screening test to make sure that the program is at least economic and the decision won't be made here. The decision to implement a program will be made in the capacity planning submodule.

We will also consider looking at some of the other tests that people are using with DSM programs to see if we can implement them also. Again, we'll have to aggregate the DSM programs into various categories for evaluation in the Capacity Planning Submodule and then once the Capacity Planning Submodule chooses particular programs, we'll have to disaggregate these programs and pass information on the selected programs to the various NEMS demand modules to that they can incorporate any changes that might occur in future penetration.

This last slide is talking about some issues that we're trying to deal with in terms of new technology penetration. In many analyses that people have done in the past there's always been considerable concern about technological optimism, especially for new and currently non-commercial technologies.

We are at this point trying to develop a database on all of the various generating technology options. We're going to ensure that the cost estimates are computed consistently with interest rates, inflation rates, consistent contingency factors, and that we, as best as we can, remove the sense of technological optimism. We're going to do this by looking at several factors that have influenced this type of information in the past, such as the degree that a particular technology departs from previously established systems.

As one would expect if a system is entirely new and has never been developed before, then its current estimate of cost might be seriously understated. Other factors are how much of the project's design has already been completed. Is this purely a paper project or has somebody actually put pieces of this together before? We're going to try to consider these factors in looking at developing some sort of adjustment factors and then these adjustment factors will be utilized to adjust the overnight costs and cost estimates for all of the various generating technologies before this information is utilized in the capacity planning submodule.

Well, at this time I want to introduce our reviewers. No slights intended here, but we've put our reviewers in order of their plane flights this afternoon so that the person with the earliest plane flight can get out of here first. I want to tell them that we appreciate all of them taking the time to go through our work and we look forward to their comments.

Our first reviewer is Dr. Martin Baughman. He is a Professor in the Department of Electrical and Computer Engineering at the University of Texas at Austin, and he's involved in a lot of research areas including the economics of cogeneration, electricity regulation and electricity pricing.

DSM Screening

- Cost-effectiveness calculations

- Aggregation of cost effective DSM programs

- Disaggregation of DSM programs selected by the ECP

Derivation of First-of-a-kind Cost Estimates

- Cost estimates will be computed using consistent interest and inflation rate assumptions.

- Consistent set of contingency factors will be used.

- Cost estimates will omit technological optimism.

- Quantitative measures of factors influencing cost growth will be used.

    - Degree of technological departure from previously established systems.
    - Percent of project's design completeness.

- Differences will be predicted and overnight cost estimates will be adjusted.

OIAF 2/93

Dr. Baughman?

DR. BAUGHMAN: Thank you, Alan.

I probably get the prize for having the thickest pack of paper here that you could pick up as you walked in the room today.

I'm here on behalf of the Edison Electric Institute and this work that I'm going to be reporting was done for the Edison Electric Institute. The draft of the presentation that you have before you is one that was prepared in late December. Since that time I have met with a subcommittee of the Economic Committee of the Edison Electric Institute and a few of the points that I'm going to make are different from what are on your copies of the presentation. I'll try to note them as I go through the presentation here today.

Let me also say, as Jeff and Alan have already pointed out, there's a great deal of interconnectiveness among the modules of NEMS and among the submodules of the electricity market module. The work that I am reporting concerned itself with the entire electricity market module, that is all six of the submodules, even though this session is focussed on the Electricity Capacity Planning Submodule only.

This first slide shows what I'm going to talk about today. I'm not going to attempt to go through all the charts that you have in the handouts before you. In fact, I'm not going to do anything with Section 5 at all, which is about the last half of the handout. But, if you want a thumbnail sketch of the various submodules, it's included. Since we've already had a presentation of at least a couple of the important submodules, I'm going to very quickly go through just a couple of points I want to add to these descriptions. Then I'm going to talk about some of the key public policy assumptions that appear to be built into the models. These are assumptions that I think the EIA may want to reconsider. Lastly, I will present my recommendations to EIA.

As background on the scope of my assessment, let me just quickly say that I've reviewed all six of these submodule CDRs.

I have also reviewed the component design reports for the various demand sectors and the Integrating Module.

These various CDR's are the basis for the report that I am presenting here today.

Let's skip the next slide and go to the key audit findings. Let me quickly just reemphasize a couple of points that have already been made and put a new perspective on a couple of additional points.

The word "ambitious" has already come up. I think that when you go through the set of CDR's that comprise this Electricity Market Module, you will see that it is truly an ambitious design. It significantly advances the previous modeling efforts of EIA in a number of ways, including the representation of competition among alternative resources and, as I've illustrated here, interregional trade in firm capacity and economy energy. It

Assessment of the Electricity Market Module of NEMS
Summary Report

Prepared by

Martin L. Baughman, Consultant

for the
Economics Committee
Edison Electric Institute
701 Pennsylvania Avenue
Washington, D. C.

DRAFT

January 1993

INTRODUCTION

The National Energy Modeling System Branch of the Energy Information Administration is in the process of redesigning the National Energy Market System (NEMS). NEMS is composed of some 40 sub-components which are integrated to project energy supply, demand, and prices nationally and regionally within the United States. NEMS will be used to perform analyses for the Annual Energy Outlook (AEO), the National Energy Strategy, and other analyses.

The Electricity Market Module (EMM) is the module of NEMS that deals with generation, transmission, and pricing of electricity, including the influence of load and demand-side management and non-utility generation supply.

The EIA has sought outside review and comment on the design of NEMS and its various components. A number of Economics Committee members of EEI expressed interest reviewing NEMS. Mr. Robert Eynon of EIA has asked the Committee to prepare a review of the Electricity Capacity Planning (ECP) submodule and present the results at a NEMS Design Review Workshop on February 1, 1993 in Washington, D. C.

The author of this report was retained by EEI to assist in the review. This document is a brief summary report on the background, scope, and results of the assessment.

SCOPE OF ASSESSMENT

The EMM is comprised of six integrated submodules. These six submodules are include:

- Electricity Capacity Planning (ECP)
- Load & Demand Side Management (LDSM)
- Electricity Fuel Dispatch (EFD)
- Nonutility Generation Supply (NUGS)
- Electricity Transmission and Trade (ETT) (Not available as of this draft)
- Electricity Finance and Pricing (EFP)

The design of each submodule is described in a Component Design Report (CDR) that has been prepared by EIA staff. The CDRs for the six EMM submodules were the principal sources of information for this assessment. Other data and information necessary for operation of the EMM submodule, however, are also provided by other modules of NEMS, including fuels prices and electricity demands from the System Integration Module, cogeneration capacity and generation from the Industrial Demand Module, and cost effective renewable capacity additions from the Renewable Fuels Module, or supplied exogenously (eg., plant capital costs, lives, heat rate, emission rates).

CDR's for selected other modules/submodules that were available as of the date of this assessment were also reviewed.

The assessment focussed on two related review topics. The first can be described as an audit of the data and behavioral assumptions that form the basis of the module's quantitative performance. This audit was based on the available documentation and component design reports. It sought to answer questions of the type: "What are the key data? What are the key behavioral assumptions? Are the behavioral assumptions empirically derived or based upon optimization? Do the behavioral representations accommodate the diverse influences on utility behavior, including ownership, fuel, marketing, regional, and regulatory factors?"

The second assessment topic focussed upon public policy assumptions of the models. Specifically addressed were the questions: "Where within the model structures do there exist assumed outcomes of current unresolved public policy issues? What is assumed as the outcome? What alternative assumptions might be considered or should be investigated?"

The key findings from of the audit and the key public policy assumptions included in the submodules are summarized below.

KEY AUDIT FINDINGS

The key audit findings are:

1. The EMM Design is ambitious. It significantly advances previous modeling efforts in its representations of:

   - Competition among alternative resources (utility vs. nonutility supplies, supply- vs. demand-side resources, refurbishment and repowering vs. retirement and replacement, FGD retrofit vs. fuel switching, renewables vs. nonrenewables)
   - Emissions trading and valuation of tradeable emissions rights
   - Possible future structures for pricing of utility and nonutility generation and transmission services

2. The EFD and ECP submodule designs embody important changes in scope from previous EIA electricity supply models:

   - These submodules combine utilities and nonutilities into a single cost-minimizing framework.
   - These submodules endogenize a national market for trading of emissions rights.

3. The EFP submodule is designed to calculate generation and transmission transfer prices separately using average cost, levelized average cost, marginal cost, and avoided cost methodologies. However, its design exceeds the capabilities of the remaining submodules.

    - Possible behavioral changes that might be triggered by the alternative pricing structures are not incorporated into the other modules/submodules.

4. The NUGS submodule design appears unfinished. There are inconsistencies and omissions that remain:

    - The distinctions in submodule architecture for the Phase I and Phase II designs of NUGS are not reflected ECP nor EFD.

    - The goal programming approach to determining nonutility capacity additions in Phase I is not retained in ECP in Phase II. Why is it introduced as only an interim measure?

    - How cogenerator capacity additions will be determined in the commercial and industrial sectors is not documented.

    - How the purchased power price is to be determined in NUGS is not clearly documented for either Phase I or Phase II.

        - The average utilization factor used in calculating the breakeven price may be inconsistent with the dispatch.

        - It is not clear whether the prices are differentiated by plant type.

        - It is not clear whether the prices calculated remain fixed over the life of the project or vary year by year.

5. The LDSM submodule design appears to be state of the art. It contains as much screening and implementation detail as other DSM screening and planning models. It does, however, contain a couple of "loose ends."

    - The industrial sector end-use categories in LDSM do not correspond to those in the industrial sector demand module.

    - The DSM disaggregation procedure is not fully specified for "scaling" programs selected by ECP to options to be implemented in LDSM.

6. The ETT submodule design . . . (Not yet available)

KEY PUBLIC POLICY ASSUMPTIONS

The submodules also contain several key public policy assumptions. These are listed below by submodule:

EED

1. Dispatching according to a minimum cost criterion is appropriate regardless of pricing structure or contractual agreement.

ECP

2. Minimum present worth utility plus nonutility costs is the appropriate integrated resource planning criteria.

3. Regulators will allow the continued recovery of the unamortized capital costs of uneconomical powerplants that are replaced by more economical alternatives.

EFP

4. No time-of-use differentiation of electricity rates is necessary. Calculation of average revenues by customer class is sufficient.

5. Historical demand charge allocations to the residential, commercial, and industrial classes will continue into the future.

6. Public vs. private utility distinction is necessary only in EFP.

NUGS

7. A disequilibrium approach to setting avoided capacity and energy costs is appropriate for economic evaluation of alternative commercial/industrial cogenerator designs.

8. The need for and/or costs of providing associated electrical services (spinning reserve, VAr support, load-frequency control, security monitoring, etc.) to nonutility generators and users of wheeling services are negligible.

9. The various non-price factors that influence utility purchases of nonutility generated power can be incorporated into the goal program described in the NUGS submodule CDR.

LDSM

10. A disequilibrium approach to setting avoided capacity and energy costs is appropriate for screening DSM alternatives.

11. DSM impacts on the transmission and distribution system, other than losses, can be ignored.

12. Fuel switching DSM options require special treatment.

13. The administrative costs of DSM programs are separable and can be allocated to specific program options.

ETT

14. . . . Not yet available.

DRAFT 12/31/92

Assessment of the Electricity Market Module of NEMS

Prepared by

EEI Economics Committee
&
Martin L. Baughman, Consultant

January 1993

DRAFT 12/31/92

Overview of Presentation

1. Scope of Assessment
2. Summary of Key Audit Findings
3. Key Public Policy Assumptions
4. Detailed Submodule Audit Results
   - Purposes
   - Key behavioral assumptions
   - Key exogenous data
   - Key inputs from other submodules/modules

619

DRAFT 12/31/92

1. Scope of Assessment

620

DRAFT 12/31/92

Scope of Assessment

1. Available Submodule Component Design Reports (CDRs)
   - Electricity Capacity Planning (ECP)
   - Electricity Fuel Dispatch (EFD)
   - Electricity Finance and Pricing (EFP)
   - Load and Demand Side Management (LDSM)
   - Nonutility Generation Supply (NUGS)
   - Electricity Transmission and Trade (ETT) (Not available as of this draft)

continued. . .

. . . continued

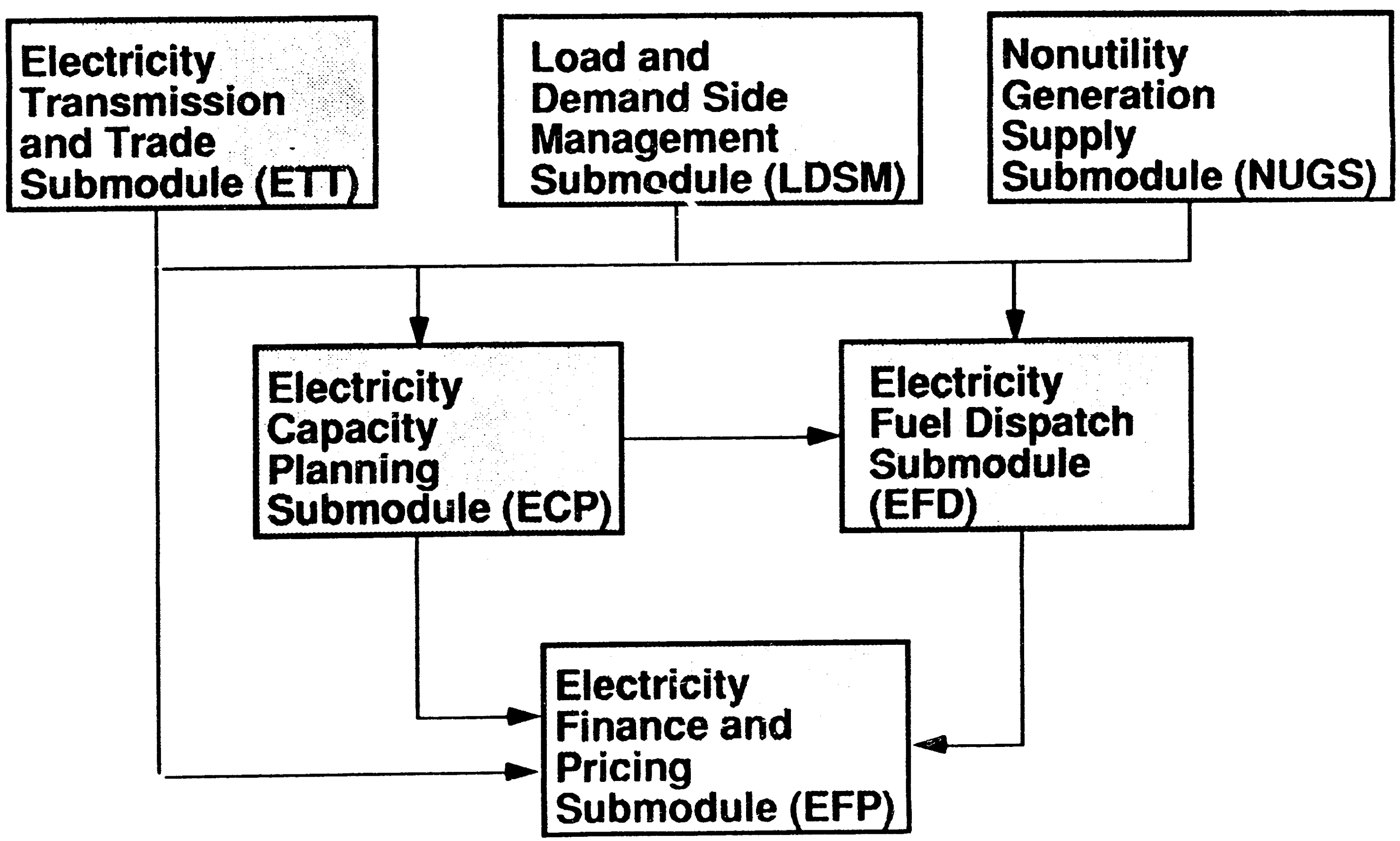
DRAFT 12/31/92

Scope of Assessment, Continued

2. Selected Other Module Component Design Reports
   - Residential Sector Demand
   - Commercial Sector Demand
   - Industrial Sector Demand
   - Integrating Module

DRAFT 12/31/92

Schematic of EMM Submodules



DRAFT 12/31/92

2. Key Audit Findings

DRAFT 12/31/92

Key Audit Findings

1. The EMM Design is ambitious. It significantly advances previous modeling efforts in its representations of:

   - Competition among alternative resources (utility vs. nonutility supplies, supply- vs. demand-side resources, refurbishment and repowering vs. retirement and replacement, FGD retrofit vs. fuel switching, renewables vs. nonrenewables)
   - Emissions trading and valuation of tradeable emissions rights
   - Possible future structures for pricing of utility and nonutility generation and transmission services

Key Audit Findings- ECP and EFD

2. The EFD and ECP submodule designs embody important changes in scope from previous EIA electricity supply models:

   - These submodules combine utilities and nonutilities into a single cost-minimizing framework.

   - These submodules endogenize a national market for trading of emissions rights.

Key Audit Findings- EFP

3. The EFP submodule is designed to calculate generation and transmission transfer prices separately using average cost, levelized average cost, marginal cost, and avoided cost methodologies. However, its design exceeds the capabilities of the remaining submodules.

   - Possible behavioral changes that might be triggered by the alternative pricing structures are not incorporated into the other modules/submodules.

Key Audit Findings- NUGS

4. The NUGS submodule design appears unfinished. There are inconsistencies and omissions that remain:

   - The distinctions in submodule architecture for the Phase I and Phase II designs of NUGS are not reflected ECP nor EFD.

   - The goal programming approach to determining nonutility capacity additions in Phase I is not retained in ECP in Phase II. Why is it introduced as only an interim measure?

   - How cogenerator capacity additions will be determined in the commercial and industrial sectors is not documented.

continued. . .

. . . continued

DRAFT 12/31/92

Key Audit Findings- NUGS Continued

- How the purchased power price is to be determined in NUGS is not clearly documented for either Phase I or Phase II.
  - The average utilization factor used in calculating the breakeven price may be inconsistent with the dispatch.
  - It is not clear whether the prices are differentiated by plant type.
  - It is not clear whether the prices calculated remain fixed over the life of the project or vary year by year.

DRAFT 12/31/92

Key Audit Findings- LDSM

5. The LDSM submodule design appears to be state of the art. It contains as much screening and implementation detail as other DSM screening and planning models. It does, however, contain a couple of "loose ends."

   - The industrial sector end-use categories in LDSM do not correspond to those in the industrial sector demand module.

   - The DSM disaggregation procedure is not fully specified for "scaling" programs selected by ECP to options to be implemented in LDSM.

629

Key Audit Findings- ETT

6. The ETT submodule design . . .

DRAFT 12/31/92

3. Key Public Policy Assumptions

631

632

DRAFT 12/31/92

Key Public Policy Assumptions

EFD

1. Dispatching according to a minimum cost criterion is appropriate regardless of pricing structure or contractual agreement.

ECP

2. Minimum present worth utility plus nonutility costs is the appropriate integrated resource planning criteria.

3. Regulators will allow the continued recovery of the unamortized capital costs of uneconomical powerplants that are replaced by more economical alternatives.

continued. . .

DRAFT 12/31/92

. . . continued

Key Public Policy Assumptions, Continued

<u>EFP</u>

4. No time-of-use differentiation of electricity rates is necessary. Calculation of average revenues by customer class is sufficient.

5. Historical demand charge allocations to the residential, commercial, and industrial classes will continue into the future.

6. Public vs. private utility distinction is necessary only in EFP.

<u>NUGS</u>

7. A disequilibrium approach to setting avoided capacity and energy costs is appropriate for economic evaluation of alternative commercial/industrial cogenerator designs.

8. The need for and/or costs of providing associated electrical services (spinning reserve, VAr support, load-frequency control, security monitoring, etc.) to nonutility generators and users of wheeling services are negligible.

continued. . .

. . . continued

Key Public Policy Assumptions, Continued

<u>NUGS, continued</u>

9. The various non-price factors that influence utility purchases of nonutility generated power can be incorporated into the goal program described in the NUGS submodule CDR.

<u>LDSM</u>

10. A disequilibrium approach to setting avoided capacity and energy costs is appropriate for screening DSM alternatives.

11. DSM impacts on the transmission and distribution system, other than losses, can be ignored.

12. Fuel switching DSM options require special treatment.

13. The administrative costs of DSM programs are separable and can be allocated to specific program options.

continued. . .

. . . continued

Key Public Policy Assumptions, Continued

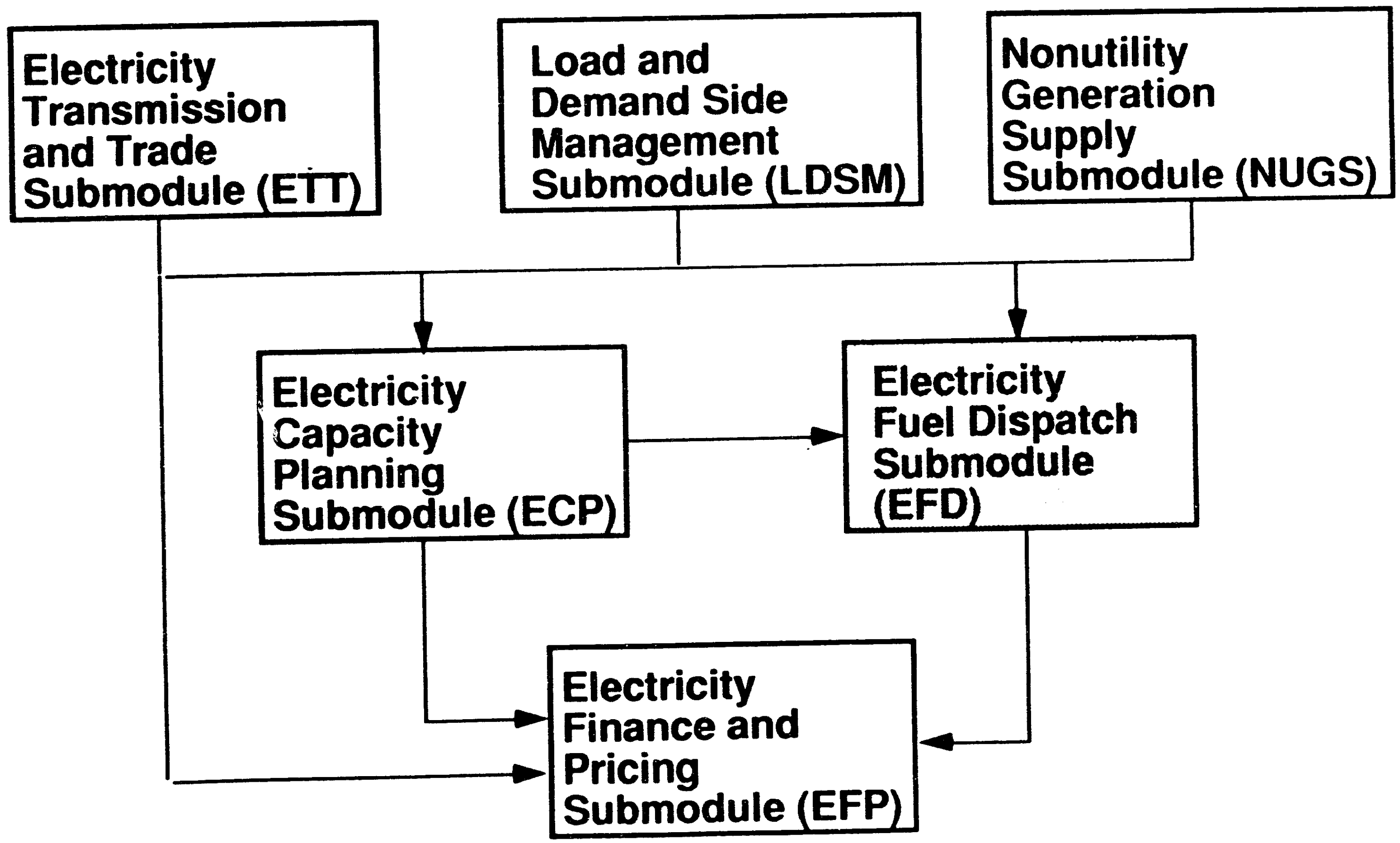
<u>ETT</u>

14. Not yet available

4. Detailed Submodule Audit Results

DRAFT 12/31/92

Schematic of EMM Submodules



DRAFT 12/31/92

Detailed Audit Results for EFD
Electricity Fuel Dispatch Submodule

Purposes:

1. To allocate available capacity(utility and nonutility) to meet the demand for electricity on a least-cost basis, subject to restrictions on emissions such SOx, NOx, and carbon.

2. To provide information on fuel and variable O&M costs to EFP.

Key Behavioral Assumptions:

1. Either an LP or heuristic approach can be used.

2. A national market functions for trading emissions rights.

3. Each of the 13 electricity supply regions is operated as a "tight" power pool.

4. No transmission, operations, control, or other significant constraints on the dispatch.

639

DRAFT 12/31/92

Key Data Used in EFD

Key exogenous data:

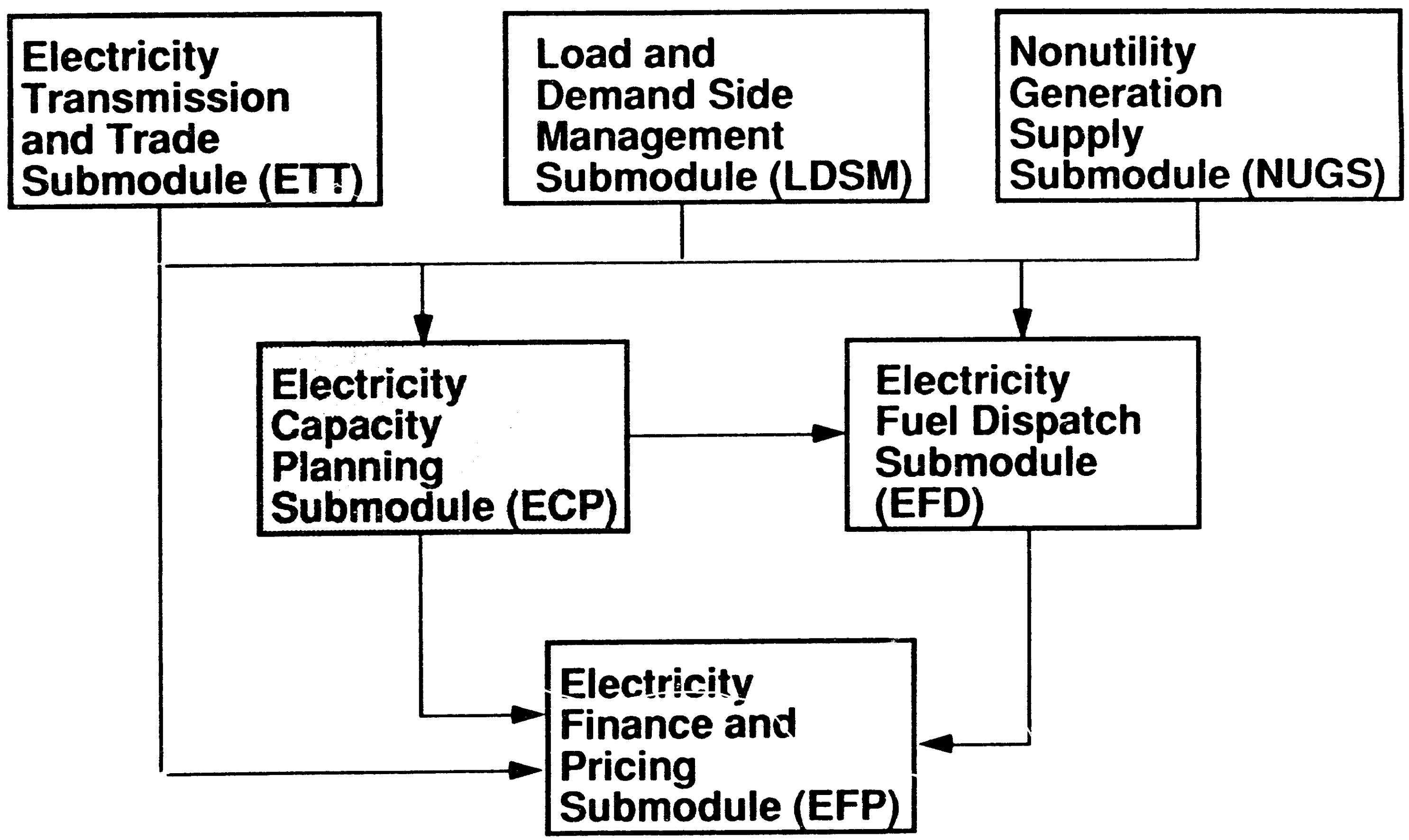
- Heat rates
- Emissions rates
- Forced outage rates
- Variable O&M costs
- Emissions standards
- Planned maintenance requirements

Key inputs from other submodules/modules:

- Generating capacity (by fuel and ownership)
- Delivered fuel prices
- T&D loss factors
- Load duration curve(s)

DRAFT 12/31/92

Schematic of EMM Submodules



DRAFT 12/31/92

Detailed Audit Results for ECP
Electricity Capacity Planning Submodule

Purposes:

1. To determine how the electric power industry will change its generating capability in response to increases in demand and environmental regulations, including consideration of the following options:

   - utility vs. nonutility supplies
   - supply- vs. demand-side resources
   - refurbishment and repowering vs. retirement and replacement
   - FGD retrofit vs. fuel switching
   - Emitting now vs. overcomplying and banking allowances
   - renewables vs. nonrenewables

2. To provide avoided costs to the NUGS and LDSM submodules.

continued. . .

642

Detailed Audit Results for ECP, Continued

Key Behavioral Assumptions:

1. Minimizing the discounted present value of meeting demand over the planning horizon subject to emissions and reliability constraints is the appropriate objective function. (LP approach)

2. Both utility and nonutility capacity additions can be planned in the same least-cost framework.

3. "Knife-edge" results can be smoothed out with appropriate sharing functions.

4. A national market functions for trading emissions rights.

5. Each of the 13 electricity supply regions is planned as a "tight" power pool.

DRAFT 12/31/92

Key Data Used in ECP

Key exogenous data:

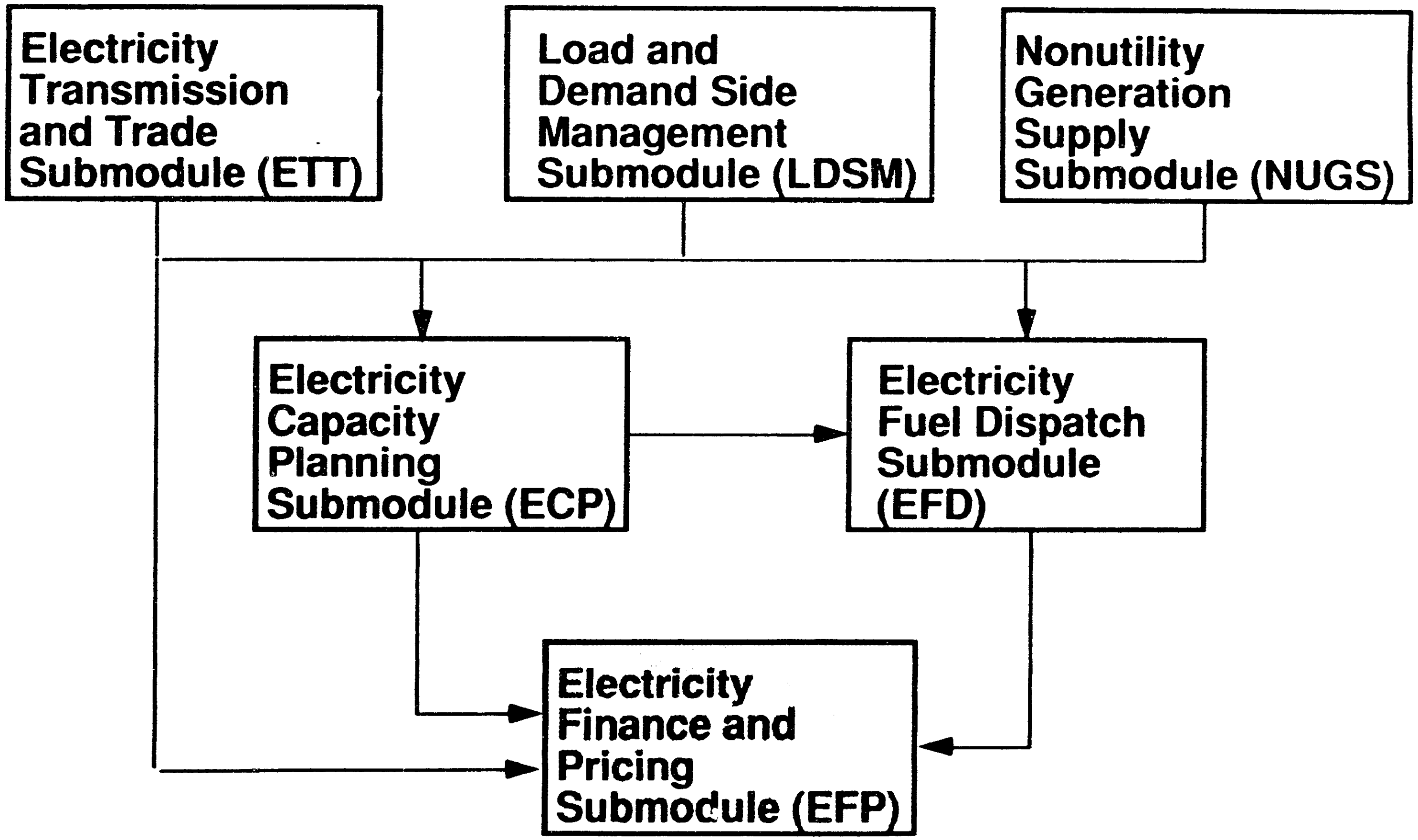
- Existing operable capacity
- Announced retirements
- Maximum fuel shares
- Heat rates
- O&M costs
- Outage rates
- Planned capacity additions
- Operating life
- Overnight construction costs
- Construction expenditure profile
- Emissions rates
- Reserve margin requirements
- Repowering, refurbishment, and FGD retrofit options and costs

Key inputs from other submodules/modules:

- Expected fuel prices
- DSM resources
- Cogeneration capacity and generation
- Intermittent renewables cost and capacity credits
- Expected load duration curve(s)
- Cost of capital

DRAFT 12/31/92

Schematic of EMM Submodules



Detailed Audit Results for EFP Electricity Finance and Pricing Submodule

<u>Purposes:</u>

1. To calculate revenue requirements and transfer prices for generation, transmission, and distribution operational functions based upon regulatory environment.

2. To provide estimates of average revenues to the sectoral demand models.

3. To calculate regional and national financial statements and associated ratios by operational function and industry segment.

<u>Key Behavioral Assumptions:</u>

1. Separate financial statements and prices can be determined for generation, transmission, and distribution activities using four different pricing algorithms...

The Pricing Alternatives Included in EFP

The EFP will have the capability of employing the following pricing algorithms:

- average cost based pricing- price determined by averaging all costs incurred over all units of service provided.
- levelized cost based pricing- price determined by dividing the equivalent uniform annual costs over the life of the project by the annual service provided.
- marginal cost based pricing- price set equal to the cost of producing the next unit of service. The short-run marginal cost includes only the variable production cost. The long-run marginal cost includes a fixed component for capacity as well as a variable component for energy.
- avoided cost based pricing- the cost the utility would have incurred if it had provided the service itself or purchased it from another supplier.

continued. . .

. . . continued

DRAFT 12/31/92

Pricing Options in EFP

Source of Energy	Generation Transfer Price		Transmission Transfer Price		Distribution Average Revenue
	New Capacity	Old Capacity	New Capacity	Old Capacity	All Capacity
IOUs, Publicly-Owned, IPPs	Average Levelized Marginal	Average Levelized Marginal	Average Levelized Marginal	Average Levelized Marginal	Average
Trade	Average Marginal		Average Marginal		
Cogen.	Avoided		Not Applicable		

DRAFT 12/31/92

Key Data Used in EFP

Key exogenous data:

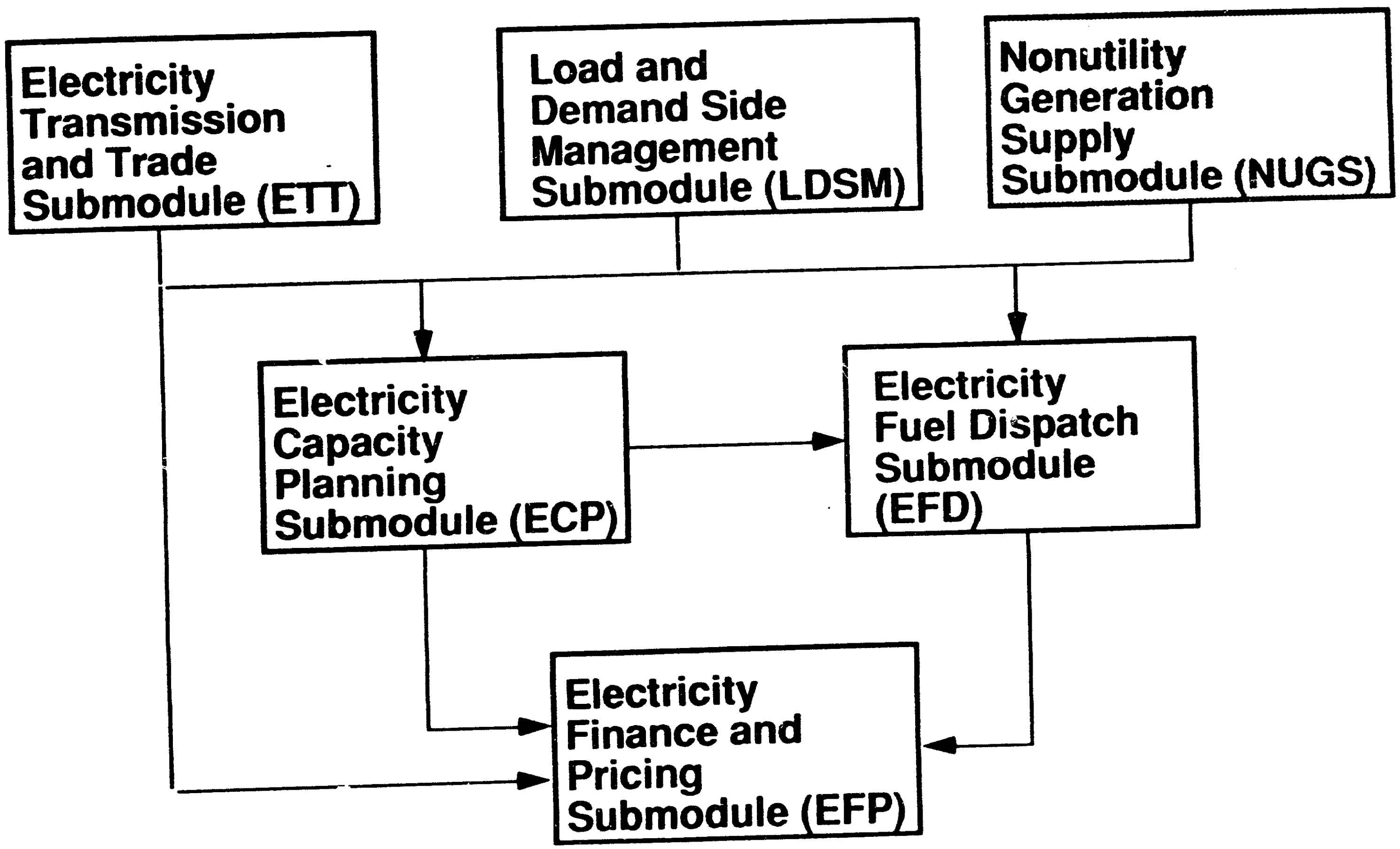
Base year balance sheet data
Capitalization ratios
Sales/leaseback transactions
New G&T capital costs
State, sales, and property taxes
Book lives, tax lives, tax schedules
T&D related O&M costs
Rate phase-in plans
New distribution plant expenditures

Key inputs from other submodules/modules:

DSM implementation costs
Electricity sales by sector
Generating capacity (by fuel and ownership)
Fuel, operation & maintenance costs
Average and marginal costs of capacity additions
Average and marginal costs of generation
Power purchased from and prices paid to cogenerators

DRAFT 12/31/92

Schematic of EMM Submodules



DRAFT 12/31/92

Detailed Audit Results for NUGS- Phase I
Nonutility Generation Supply Submodule

650

Purpose:

1. To provide the ECP and EFD submodules with capacity (existing and new builds) and generation.

2. To calculate the purchased power price for utility purchases of nonutility generation.

Key Behavioral Assumptions:

1. The relative economics of NUGS vis-a-vis utility capacity additions can be captured in the breakeven prices vs. levelized average costs, respectively.

2. Replace ECP capacity builds with economical NUGS subject to a set goals and constraints (using a goal programming methodology).

3. The logic for determining purchased power price is not given.

DRAFT 12/31/92

Key Data Used in NUGS- Phase I

Key exogenous data:

- Existing operable capacity
- Min and Max size of unit
- Fuel type
- Heat rates
- O&M costs
- Average utilization
- Planned capacity additions
- Operating life
- Overnight construction costs
- Construction expenditure profile
- Emissions rates
- Tax and depreciation data

Key inputs from other submodules/modules:

- ECP capacity builds
- Levelized costs of ECP builds
- Cogenerator capacity additions, capacity, generation, and fuel use
- Emissions allowance costs
- Expected fuel prices
- Cost of capital

DRAFT 12/31/92

NUGS Phase I
Hierarchy of Goals

1. Replace as much utility capacity and generation with nonutility capacity and generation as possible.
2. Limit or encourage the penetration of specific plant types.
3. Limit or encourage the use of particular fuels.
4. Minimize total costs.

653

DRAFT 12/31/92

Detailed Audit Results for NUGS- Phase II
Nonutility Generation Supply Submodule

Purposes:

1. To provide cost, performance, and financial data on nonutility capacity (existing and new) to the ECP and EFD submodules.
2. To calculate the purchased power price for utility purchases of nonutility generation.

Key Behavioral Assumptions:

1. The logic for determining the purchased power price is not given.

DRAFT 12/31/92

Key Data Used in NUGS- Phase II

Key exogenous data:

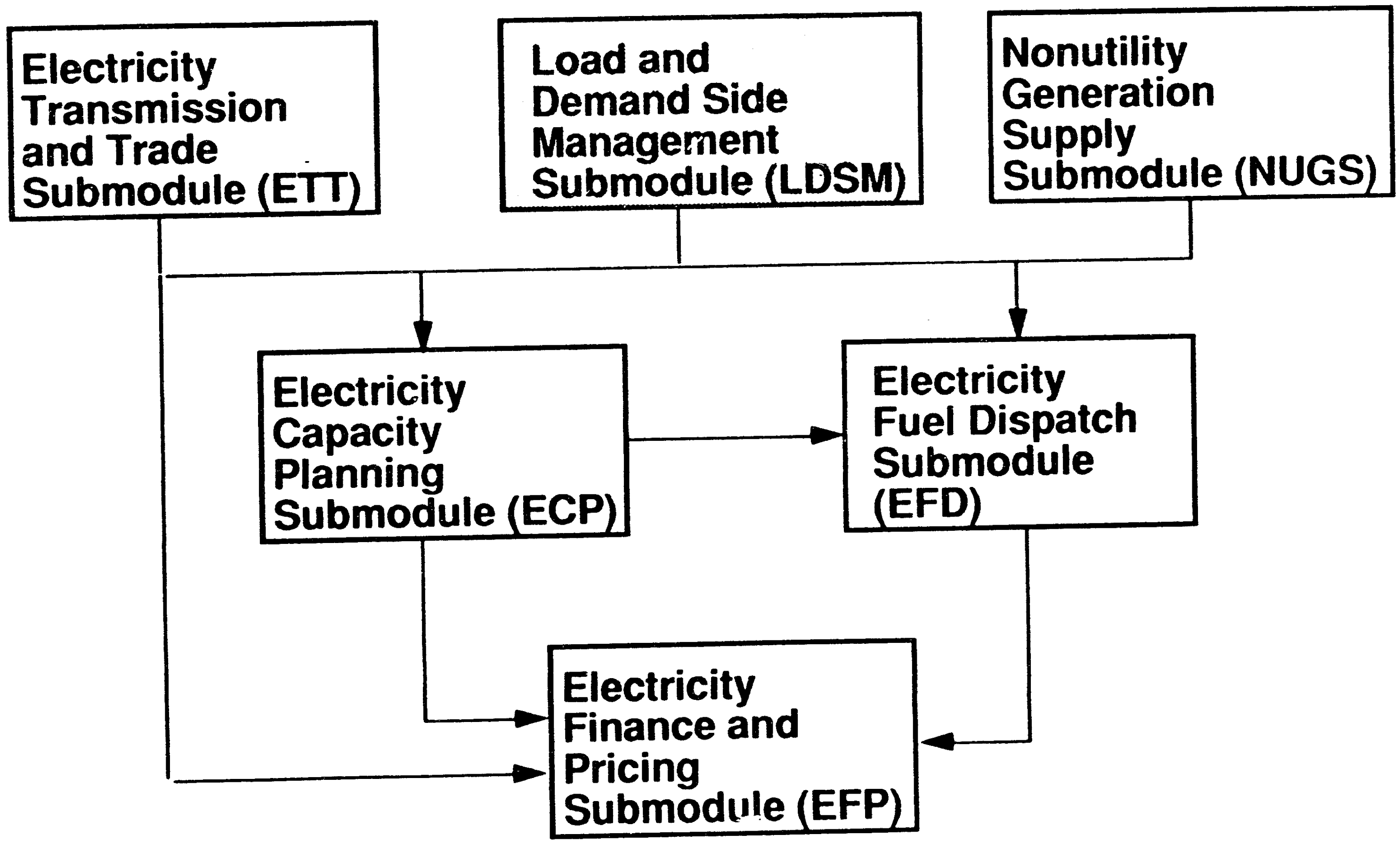
Planned capacity additions
Fuel type
Heat rates
O&M costs
Utilization limits
Operating life
Overnight construction costs
Construction expenditure profile
Maintenance schedules

Key inputs from other submodules/modules:

ECP utility and nonutility capacity builds and levelized costs
Cogenerator capacity additions, capacity, generation, and fuel use
IPP and SPP utilization
Tax and depreciation data
Emission rates
Cost of capital

DRAFT 12/31/92

Schematic of EMM Submodules



DRAFT 12/31/92

Detailed Audit Results for LDSM
Load and Demand Side Management Submodule

Purposes:

1. To translate total electricity consumption forecasts into system load shapes.
2. To develop utility DSM programs for potential inclusion in future utility capacity expansion plans.
3. To translate census division demand data into NERC region data, and vice versa.
4. To represent the impacts of intermittent technologies on load shapes.

continued. . .

. . . continued

DRAFT 12/31/92

Audit Results for DSM, Continued

Key Behavioral Assumptions:

1. The appropriate DSM screening test is the California Total Resource Cost test.
2. Projected DSM option maximum penetrations can be estimated
   a. assuming rebates are provided to yield a 2 year payback
   b. payback acceptance curves
3. Annual and cumulative participation is a linear function of current market participation and maximum market penetration.
4. Options can be aggregated into programs for consideration in ECP.
5. Screened DSM programs exhibit constant returns to scale.
6. Programs selected by ECP can be "scaled" to determine participation levels of options.

DRAFT 12/31/92

Key Data Used in LDSM

<u>Key exogenous data:</u>

For each end use: Typical load shapes and allocation factors
Energy and peak T&D loss multipliers

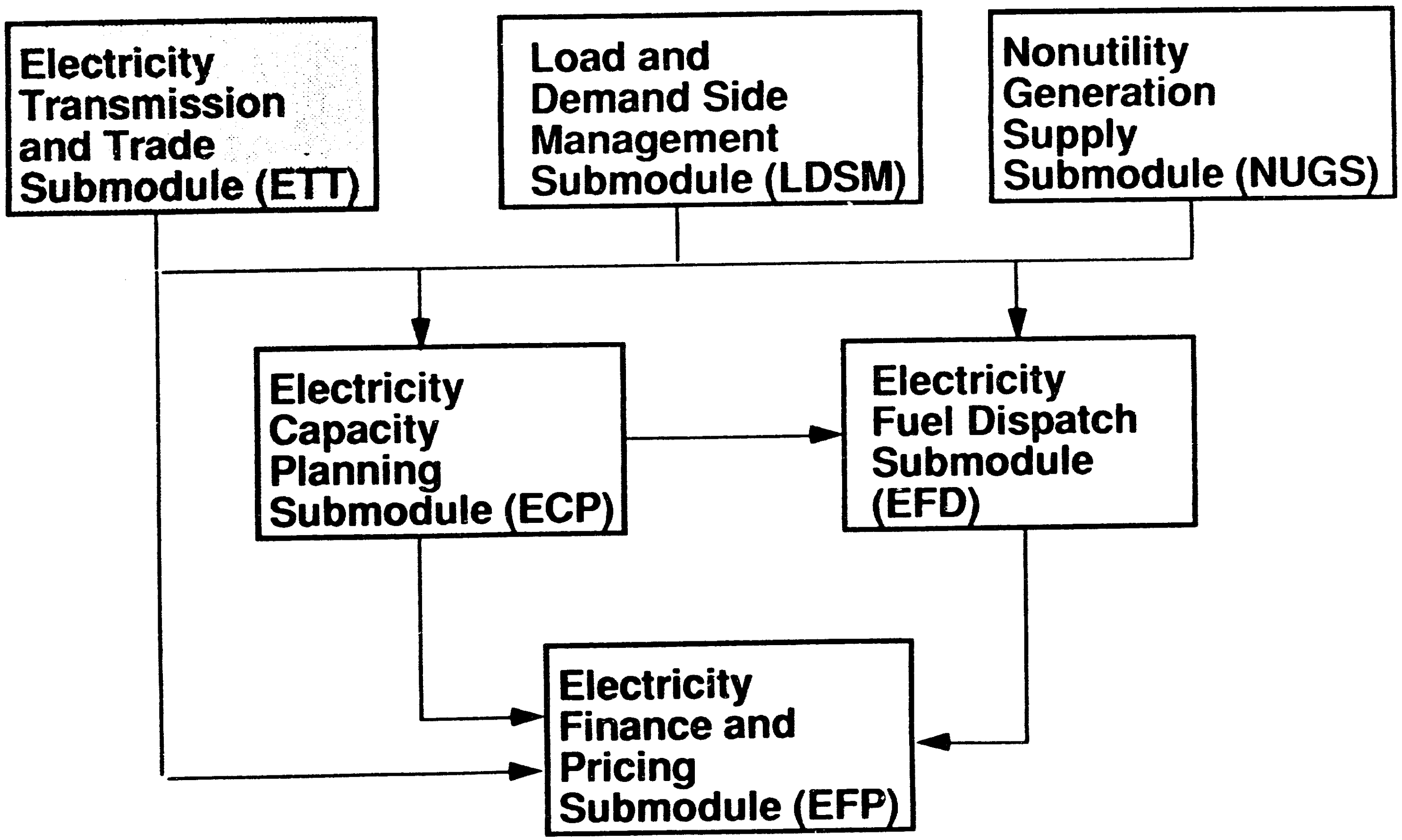
For each DSM option:
Target market- new, existing, or retrofit
Incremental capital costs, operating costs
Incremental LDC impacts (by segment)
Administration costs
First and last years option available, option life
Payback acceptance curves, or
Max market penetration, annual participation, & rebates

<u>Key inputs from other submodules/modules:</u>

Hourly generation patterns of intermittent renewables
Unit energy consumption (by equipment and end-use)
Technology installation and operation costs
Electricity demand (by region, sector, end-use, and technology)
Target market sizes (by region, sector, end-use, and technology)
Projected electricity rates
Projected avoided utility costs

DRAFT 12/31/92

Schematic of EMM Submodules



DRAFT 12/31/92

Detailed Audit Results for ETT
Electricity Transmission and Trade Submodule

Purposes:

1.

Key Behavioral Assumptions:

1.

DRAFT 12/31/92

Key Data for ETT

Key exogenous data:

Key inputs from other submodules/modules:

advances previous modeling efforts in modeling emissions trading and valuation of tradeable emission rights. It also advances previous efforts -- and I have some concern about this -- but it also advances the previous modeling efforts in terms of the representation of possible future structures for pricing utility and non-utility generation and transmission services. I'll say more about this later. Now lets review the audit findings.

It's already been pointed out that the electricity capacity planning submodule -- and you can also include the Electricity Fuel Dispatch Module here -- they both incorporate both utility and non-utility sources of generation into a single cost minimizing framework for the purposes of simulating operations and for the purposes of capacity planning. This is an important change in concept in the way that these two components of the utility business were represented previously by the EIA.

It's already been mentioned that the outputs of Electricity Capacity Planning are the primary inputs to the Electricity Finance and Pricing Submodule. Let me point out to you that this Finance and Pricing Submodule is designed to calculate generation and transmission transfer prices, separately, for these activities in the utility sector. Moreover, it is designed, supposedly, to have the capability to do this with average cost pricing principles, or as alternatives, using levelized average cost, marginal cost, avoided cost methodologies applying to either new and existing capacity within the generation and transmission sector. I think this has some interesting implications for how or what should be included in Electricity Capacity Planning Submodule and that's the reason that I wanted to mention it here. Moreover, the average retail prices are determined for just three sectors in this submodule; namely only the residential, commercial, and industrial sectors. I'll come back and touch upon this aspect of this submodule design later.

One of the things that's of concern to me concerning this representation of pricing alternatives is the possible behavioral changes that might be triggered in the other submodules if you were to move, for example, from historical average cost pricing to, let's say, marginal cost pricing. You might expect that this would trigger changes in the planning and operation of many bulk power generation and transmission facilities. Yet, the way the EIA models are structured, the Capacity Planning Submodule, the Fuel Dispatch Submodule, and the other modules, will all give exactly the same results whether marginal cost pricing or average cost pricing is used.

I think there are some key feedback loops included if these alternative pricing methodologies are going to be analyzed. Among these are the effects of risk and the effects of funds flow, internally-generated funds and new external financing, and things of that sort.

I won't get into the details of some of the issues presented here, but I think that the NUGS submodule design appears to be unfinished. There are some inconsistencies in the way that this module is presented when compared to the other submodules. You can read about these in this list that I have here. I think that -- and you'll see this in my list of recommendations -- that going back and filling out the details of the design of this important sector module is something which should be of high priority and, as I understand it, is already getting some attention from EIA.

Let's go on to the audit results for LDSM. Alan gave you a brief sketch of the Load and Demand-Side Management Submodule. He mentioned that it does rely upon the total resource cost test as a screening criterion. He also mentioned that the model was structured to calculate rebates that would go to the participants in a particular option to provide incentives for those participants to get involved. The documentation states that these rebates are set to yield a two year payback, though I believe that EIA might want to use other paybacks. Alan showed the penetration curves that might result for alternative paybacks that the customer would get.

Another important point here is that the submodule relies exclusively upon the total resource cost test as a DSM screen. The total resource cost is the total cost that both the participant and the utility incur. What nets out of the total resource cost is the effect that the incentives that the utility pays to the participants in a particular program might have on the non-participants.

It's entirely possible, even probable, I would say, given the two year payback as a criterion for setting rebates, that the way this submodule is now structured it would find economical and rely upon large amounts of DSM brought about by these incentive payments. These same payments, however, might actually increase the cost of providing service to the utility's non-participants, or those customers of the utility who were not the direct beneficiaries of the programs which were being adopted. For this reason, I think that the EIA will want to consider additional screening. I suggest that the ratepayer impact measure test be included in the LDSM submodule architecture as a screening device.

There were a couple of other minor audit problems in this submodule. For example, one of the DSM options included and described in the DSM submodule has to do with motors, yet motors are not an identified end use in the industrial sector demand module, so I think there's an inconsistency to be worked out.

In addition, a DSM disaggregation procedure is applied to produce programs of options for consideration in the Capacity Planning Submodule. How the options are aggregated, then disaggregated after the capacity planning is solved is not fully discussed.

Various options can be characterized by their life cycle costs over time, year by year, and their impacts on particular segments of the load curve. Those options get combined together into bundles, or programs, for the purposes of treatment in the Capacity Planning Submodule.

After the level of effort in these "bundled" programs is selected by ECP, the bundles then have to then be split out to specific implementation options. I don't know whether the splitting is to be done based on the present worth of the cost, whether it's to be done based upon the first year's savings in peak, or some other load demand block, and a variety of questions of this sort. These are some remaining unanswered questions in this regard.

The next slide is the final slide of audit results. It is the list of audit results for the electricity transmission and trade submodule which was documented here very recently. To get a full appreciation of what's going on with electricity capacity planning, you need to be aware that trade between the regions is made possible in this submodule. In fact, the submodule is really a post-processor of the results that come out of the Electricity Capacity Planning Module.

With that, let's go to what I think are some of the important key public policy assumptions that are included in the model. This is an industry in transition and there are lots of unresolved public policy issues that will somehow work themselves out over the next several years. What I was interested in here was identifying where there were assumptions about the outcomes of these public policies which appear to be built into specification of the submodules. I wanted to identify these because I think that the EIA may want to go back and build in a range of possible outcomes in each case.

So, let's go through the list of the submodules.

In Electricity Fuel Dispatch, the dispatching is based primarily upon a minimum cost criterion. This is regardless of the kind of contracting arrangement or pricing structure that may exist between the non-utilities and the utilities. One might expect that certain of these contracting arrangements might change the relative economics of using these alternative resources vis-a-vis the utility resources, but such outcomes are not accommodated in the Electricity Fuel Dispatch Submodule.

In the Electricity Capacity Planning Module, it's basically minimum present worth of the utility plus the non-utility costs that is used as the integrated resource planning criterion, at least as far as this submodule is concerned. With the interest in many states in incorporating such things as externality costs into the capacity planning process, perhaps some alternative criteria should be considered here.

It's also assumed in the capacity planning submodule that regulators will allow the continued recovery of unamortized capital costs of uneconomical resources that are replaced by more economical alternatives. In other words, at least under the historical average cost pricing logic, there's always full cost recovery of new investments (except for a few exogenously supplied exceptions to that that reflect some disallowances that have already been announced in the various regions of the country).

Also built into the ECP submodule, is a lack of capability for stretching out the construction time of committed units or canceling planned units after construction has begun. This can be particularly important in adapting to unexpected changes in economic conditions, as the utilities have experienced in the past. Yet I don't think that the structure of the model, as it's currently set out, can accommodate this sort of response.

In the Electricity Finance and Pricing Submodule, there exists no time of use differentiation of the rates anywhere within the various sectors nor any further sectoral desegregation of rates beyond the residential, commercial, and industrial categories. I think that, particularly when you're talking about various types of storage technologies, that time of use rates may be important in looking at the economics.

I also think that in some of the industrial sectors, particularly those represented with a great deal of detail in the industrial demand module, that more disaggregation of rates might be desirable. The rates that some of these industrial customers pay, and the advantage they take of things like dump power and interruptible power may be very important to their decision to consume electricity as well as their investment decisions with regard to self-generation. Yet none of this is included in the pricing submodule. The submodule instead assumes that you don't need to deal with this kind of price detail. I think that this is a simplifying assumption, and it may not be one that applies in all cases.

It is also assumed that the historical demand charge allocations in the residential, commercial, industrial sectors will continue into the future. This is assumed regardless of the competitive conditions that may prevail in this industry in the future.

Finally, in the Electricity Finance and Pricing Submodule, there exists a public versus private utility distinction to account for their differences in finance and costs of financing. But this distinction is only in the finance and pricing submodule. In other words, it doesn't carry over to the capacity planning submodule, nor is it included in the transmission submodule via, ownership of transmission, trade, or anything of that sort. This is another simplifying assumption, and one that I believe leads to important public policy limitations.

In the NUGS submodule, the EIA uses what I call a disequilibrium approach for establishing the avoided costs. This means that the short-run costs are used whenever additional capacity is not needed and then the long-run marginal costs are used when additional capacity needs to be installed. It is assumed that this disequilibrium approach is appropriate for the economic evaluation of all non-utility generation, including the commercial and industrial cogenerators and the designs and the amounts they install. In fact, state commissions use a variety of avoided cost methodologies and I think that the model should be capable of handling a range of possible avoided cost methodologies rather than just one.

The next point concerns the need for and/or the costs of providing associated electrical services. Here I have in mind things like backstand power, spinning reserve, VAR support, load frequency control, security monitoring and other types of services. None of these are accounted for in the NEMS modules. Rather it is assumed that the costs of providing them and/or the need for them is negligible. I think this is an important simplying assumption that is built into the models as currently articulated.

It is assumed that the various non-price factors that influence utility purchases of non-utility generated power can be incorporated into a goal programming logic documented in the NUGS submodule CDR. This logic can accommodate things like capacity mix constraints, capacity mix goals, goals with regard to renewables versus non-renewables and things of this sort. Curiously, however, the goal programming logic that is included in the NUGS documentation for phase 1 implementation has been dropped in the later phase 2 plan of work.

In LDSM, again a disequilibrium approach is used for estimating avoided costs. It is also assumed that any DSM impacts on the transmission and distribution system other than losses can be ignored. That is, there's never a need to calculate any economics savings that might be assigned to reduced T&D needs accompanying the implementation of DSM programs. The rebates for the screened programs, that is those options that pass the total resource cost test, are all set to provide a two year payback according to the documentation. I believe the payback should be a parameter, not held constant. It seems like an easy thing to implement.

It is also assumed in the LDSM submodule that the administrative costs of various DSM programs are separable, or that you can allocate them to specific DSM options for the purposes of evaluating those alternative DSM options. Sometimes this is a difficult thing to do.

Intraregional transmission constraints are neglected entirely. It's assumed they can be ignored. No explicit treatment of transmission wheeling is assumed to be necessary. This is a very important assumption and a limiting assumption and one we need to make note of, particularly in light of the Energy Policy Act and some of the new authority it grants FERC and the issues facing this industry.

Interregional transmission flow capacities are characterized and approximated by the NERC data on installed incremental transfer capabilities. Those of you familiar with this data know that the emphasis here is on "installed." There's no provision here for outage contingencies of any kind between the regions. In other words, the capacity to transport electricity between regions is based upon installed capability and does not take into account reliabilities or outage contingencies.

The next point I would like to make concerns the market sharing features incorporated into the electricity capacity planning model for smoothing out the knife edged behavior in that model. In the ETT submodule, these ideas are not extended, and the assumption is they need not extend, apparently, to the interregional and international trade activity. The value of the market sharing logic is, as Alan talked about earlier, when you have two technologies that are very close to one another in total cost, then the sharing feature will assign part of the market to each simply because their costs are very close to one another.

As far as I can see, the way that the transmission and trade submodule is specified, if a neighboring region can supply power to my region at a tenth of a mil per kilowatt hour less than I can produce it for myself, then they're going to get all the market that they can supply at that tenth of a mil per kilowatt hour. No sharing logic to preclude such outcomes was included in the documentation of the electricity transmission and trade submodule.

Let me at this point list six recommendations that I have for EIA as a result of this endeavor. My list of recommendations is organized from the easiest to the most difficult to accommodate and implement.

First, I think the EIA needs to go back and have a look at the NUGS submodule documentation and fill out a lot of the details there in light of the specification of the other submodules at this point in time.

Secondly, I think the EIA should rethink the behavioral assumptions in the various submodules (described above) that might be affected by the alternative pricing methodologies included in electricity finance and pricing submodule. I believe there either needs to be a tie to the other submodules to include the responses that would be triggered as one moves from one pricing methodology to another or EIA ought not to work on the pretense that they're actually analyzing the effects of these alternative pricing methodologies.

The third recommendation is that the EIA should review the list of policy assumptions that I've documented here and redesign the modules to accommodate a range of alternative assumptions, not just one possible policy outcome.

The next slide is my set of three last recommendations. They stem from my strong belief that a lot of what comes out of a model like this is not in the structure or the form of the equations specified, but rather it depends on what you put in the model for data. Of utmost importance is where you get the data and how you use it to analyze the issues that you want to analyze. Nowhere in any of the EIA documents describing the various modules was there any mention of validation or the issues that validation consideration raise. I think this should be given some attention here very early on, including even the design of validation experiments at this stage of the design.

Also, I believe that EIA needs to document the data that are used, with confidence limits on the data and with specification of the sensitivity analyses that would be desirable as a matter of routine when applying the model because of the uncertainties. Finally, I recommend the EIA report the results of the validation efforts and the data in a timely fashion, preferably before the model is actually used.

These are my comments. I thank you for your attention.

I'll turn the meeting back to you, Alan.

MR. BEAMON: Let me get my list in the right order here.

Mr. John Hughes. Mr. Hughes is Director of Technical Affairs for ELCON and in that capacity he provides technical and analytical support to ELCON's interventions before FERC and the EPA and testimony before Congress.

Mr. Hughes?

MR. HUGHES: For those of you who aren't familiar with ELCON, ELCON is an association of 22 large industrial electricity consumers and they have facilities in just about all of the 50 states, major facilities in most of them, as well as all over the world. Most of the ELCON members are served by many different utilities in different parts of the country and so they tend to take a national view on how electricity policy issues should be framed.

I appreciate following Martin because his comments are excellent and it gives me the chance to be a little briefer than I otherwise might have been. I originally asked to be a reviewer because of my interest in the potential role of DSM in NEMS. After looking at that CDR, I realized I had to look at the other CDRs. I ended up looking at six of them altogether.

If this system is going to be used for more than policy analysis, that is, if it's inevitable that the model will also be used for forecasting the future, because EIA will not have the luxury to say no if somebody in the White House wants a forecast from it, then we need to look at what's going to happen to the electricity industry.

Unfortunately, the industry is going to get turned upside down. That was made a fait accompli by the Energy Policy Act of 1992 which President Bush signed only last October. We believe parts of that Act were triggered by a pervasive system of rate disparities that exist throughout the nation. You can go from county to county within a state, or travel just a few miles and the local electricity rates will vary drastically.

In many of the large industrial states where ELCON members are concentrated, the rates in one part of the state are a third or less of what they are in another part of the state. These are states where all the utilities in that state are regulated by the same state PUC. All those utilities have the option to use the same technologies and the same fuels. And while there may be some differences in the loads they serve, they do not justify the tremendous degree by which the rates vary and so there's a problem there.

The problem, in its most simple terms, is a lack of an active competitive market, meaning that at least at the wholesale level, electricity is not allowed to behave as a commodity. In fact, electricity prices are more like real estate prices. So we have an industry characterized by gross rate disparities, and I also want to point out that those rates are not in "state of equilibrium." Who knows what they really reflect?

In many parts of the country, existing retail rates facing industrial users far exceed long-run marginal costs with or without selected social costs or externalities. And so, with these rate disparities we also have market distortions that are not likely to be eliminated anytime soon. However, depending upon how the new Energy Policy Act plays itself out, electricity markets will be impacted significantly in the time horizon of the NEMS model.

In the remainder of my remarks, I want to focus on two aspects of the EMM. First, DSM -- and I will state right off that I believe, as designed, NEMS over-models DSM as a resource. The second aspect will be that NEMS may under-model the nonutility power sector.

First, the nonutility sector. Everybody should know the term "EWG" by now. It stands for "exempt wholesale generators." Congress established these EWGs in the Energy Policy Act, in part, because it was mesmerized by the growing independent power market that Congress itself established with PURPA in 1978.

PURPA allowed the establishment of qualifying facilities or QFs. Most QFs are industrial cogenerators and, after some fits and starts during the early 1980s, they have become a very substantial component of the incremental supply to the electric utility sector. They presently account for roughly 50 percent of all new capacity added to the grid. However, QFs that are industrial cogenerators must be tied to a steam host. Under PURPA, there have been a variety of ingenious ways to try to get around that steam host problem, because there are a lot of efficient ways to generate electricity that don't entail the act of simple cogeneration.

Congress passed the Energy Policy Act to promote competitive wholesale bulk power markets. It believes that utilities no longer have an exclusive monopoly on the generation of power and that utilities should compete head-on with true nonutility generators (the old IPPs or independent generators) as well as among themselves. During the last few years many utilities established affiliates which are capable of building units that serve other utilities.

EWGs represent the combined sources of what used to be called IPPs (or the "true" independents), and APPs, which are affiliate power producers. I think it bears in mind that a distinction should be made between the two and I think there will be significant differences in the way the two entities are regulated (or unregulated) under the new Act.

As a little footnote, I'd like to raise an issue that did not get into the energy bill and which is now subject to an inquiry by the FERC. It is regional transmission groups, or RTGs. Some people think these are the power markets of the future. How they will form, how many will form is anybody's guess, but many observers of the power industry believe that they are inevitable. Major interests within and outside the sector are aggressively fighting for their establishment. I think NEMS needs to be flexible and capable of embracing these RTGs. The current arbitrary breakdown by NEMS into regions may be incompatible with the development of these RTGs.

Now, I want to go back to my roots with the industrials. A serious concern with the way NEMS portrays the industrial potential to generate electricity is the single-minded focus on industrial generation as cogeneration. What's missing is the option that industrials may decide to be EWGs rather than QFs in the future, even if they have a steam host. Why would they become an EWG? Because it is one more way to deal with rate disparities.

One way industrials are going to eliminate the onerous consequences of rate disparities is to become EWGs and bypass the traditional electric utility. There's nothing in the law that prohibits an industrial from owning an EWG, taking the power it needs from the EWG and then going to the FERC to get a transmission order to have the rest of the power wheeled somewhere else. I think that EWGs that are partly owned or wholly owned by industrials may play a significant role in how the future structure of the industry is going to shake out. This needs to be recognized at least as an option or a menu option in NEMS.

But again, it's very difficult to forecast what's going to happen. If one looks at the transition of other industries after deregulation such as telecommunications, the airlines and so on, one observes that they were all followed by unprecedented growth in the demand for their services. I'm not convinced that won't happen under the new Energy Policy Act within the electricity industry.

So, we must question all those forecasts with downward sloping trends because DSM programs are going to eliminate the need for lots and lots of new capacity in the future. I find those forecasts inconsistent with the promotion of competition in the industry.

Finally, several places in the documentation on the industrial module, there's an allegation that industrials are not very price sensitive. I owe my job to the fact that industrials are very price sensitive. They spend an enormous amount of money in litigation at the state and federal levels dealing with electricity rates because it is cost beneficial for them to do so. I think a feedback loop involving energy prices on an expanded array of options that industrials may elect to use based on these prices would be a welcome addition to the NEMS system.

I would like also to suggest that where industrial subsectors are modeled, those industries that own resources such as gas, coal, lignite should be more explicitly modeled. Many chemical companies, for example, own those resources. I think the Energy Policy Act (i.e., the ability to become an EWG) creates the option to form a business where an owner of gas reserves will make more money selling electricity than they will selling gas and so they will build power plants. They now can get the transmission to get the power wheeled to market. I think there needs to be an assessment of what that potential is because I believe that it could be quite significant. It was no mystery that the gas industry (and many proponents of the gas industry) were aggressive supporters of the transmission access provision in the Energy Act last year.

On DSM, I said in my opening comments that I thought the current design may over-model DSM as a resource. I want to emphasize "as a resource." It does not over-model DSM. In fact, it does a very good job and I think that those people that have watched DSM evolve since the 1970s will recognize that the approach that was adopted is very good. I really can't question it.

However, DSM as a resource is more of a mythology than it is a proven fact. When you look at the track record of the utility industry and the supporters of DSM, there is very little actual evidence that DSM has delivered a resource in the same sense that a power plant has delivered a resource. That doesn't mean that these programs don't have their merits. They may end up being expanded public relations or marketing programs.

The Energy Policy Act, in Title I, in a section far removed from the title that is going to change the power industry, there is a strong federal charge that all states look at DSM. In fact, they are required to consider it in formal rulemaking processes. I would argue that even those states that think they've already done it will probably have to revisit the matter to conform with the "fine print" in the Act. Some of that fine print involves the measurement and evaluation of the energy savings that are achieved by DSM programs.

DSM is measured and evaluated (or should be measured and evaluated) using the same tools of marketing that large marketing-based corporations use, and they have the same limitations. I find it hard to believe that utilities can take these tools and somehow fine tune their customers' demands in much the same way that they can throttle a power plant up and down to match the loads.

Industries that rely on very extensive marketing campaigns and sophisticated market research staffs to maintain their market share or to develop market shares, must spend an enormous amount of money. Utilities haven't begun to realize the scope of these expenditures. Also, I think there's a misconception that marketing-based firms are very good at what they do.

Note, Coca Cola, a big marketing leader, used these same tools to introduce new Coke. They are the same tools that Procter and Gamble used to reconsider its choice of a color for a popular shampoo, Prell; the same tool that MacDonalds used to try to push a nonfat hamburger. Selling a nonfat hamburger is sort of like trying to sell warm ice cream. Everybody in the Washington area knows the experience of Hardees, which attempted to buy Roy Rogers and do away with the Roy Rogers name only to find out that they lost a lot of customers as well. People preferred Roy Rogers over Hardees, so they had to change the name back.

Wrong decisions were made with the same tools that need to be used to evaluate DSM. So for this reason I'm somewhat skeptical. Since those are the tools that have to be used (since direct metering of each DSM option is prohibitively expensive), I think DSM as a resource is very self-limiting.

Finally, on the choice of the use of the total resource cost (or TRC) test, I'm not recommending that EIA take it out. ELCON is famous for opposing the total resource cost test, in large part because the test allows unlimited subsidization of one ratepayer by another ratepayer. No cap is put on the level of subsidies. Dollars that are taken out of one pocket are put in another and basically wash out of the TRC.

I would highly recommend adding the other tests that are well-known, such as a RIM test. I would argue that the total resource cost test would define one end of a range and maybe the RIM test or the utility cost test would define the other end. That range defines an optimistic scenario for what DSM can possibly deliver.

I want to end my comments here.

I do want to say I enjoyed reading the CDRs. I've spent many years working with utility planning models in a professional capacity. NEMS has given me a good chance to get back into it.

I wish the EIA an awful lot of luck in this very heroic exercise.

Thank you very much.

MR. BEAMON: Thanks, John.

Our final reviewer is Howard Mueller from the Electric Power Research Institute. He's the Manager of Strategic Planning. He's responsible for managing the development of EPRI's corporate, strategic, and business plans and the development of their membership strategies.

Howard?

MR. MUELLER: Thank you, Al.

And before that I managed our utility planning R&D program and that's the hat that you see me wearing at the moment.

Little introductory comments. First place, I think we all share the same respect for what EIA has bitten off here. It's a very ambitious program. You've done a lot of very good things.

A little note on personal history. My first day at the Electric Power Research Institute was the day in which I held a meeting possibly in this building with EIA, participating in a review of the IFFS model, the predecessor modeling system to the current one. There's been a whole lot of evolution in the modeling in the subsequent ten years.

There's also been an awful lot of evolution that we've already spoken to in the industry that you're trying to model and analyze, and I don't think that comes as news to anybody. It's reflected in some of the things we've said already.

There's an evolution in the kinds of issues you're trying to be able to cope with and those issues shape the modeling you've done, for example the focus on environmental issues and demand management issues. There's been a dramatic change in the structure of the industry itself and the participants in it. We've spoken to IPPs. The word at the time when PURPA was out of the bassinet, maybe, but still in the crib ten years ago was nonutility generators and QFs. We now think of very large producers of bulk resources. And there are technical challenges that have shown up in the landscape, things like management of transmission access, management of wheeling and the like, things not necessarily well-reflected yet in our modeling.

As John Hughes just said, as you look out into the future of the time period the industry that you're trying to capture in the modeling capability you're building at EIA, the industry is going be turned on its head. In fact it is in the process of turning itself on its head with some help from Uncle Sam. There are major changes coming. Marty Baughman spoke to some of the implications of those for the modeling system you've developed.

I think it's worth noting that, as a planner and a modeler in my past life, I find we're really good at modeling today's environment and yesterday's. Our challenge is to try to figure out how to cope with the things we see coming down the pike. With the industry turning itself on its head, that's the challenge you face in the modeling system. You have the disadvantage, and I think everybody should note this as they look at the NEMS system in the electricity module, that you're trying to do that right at the point in history in which we're undergoing the changes. We don't know the ground rules. We don't know how this system is going to work out.

Your challenge is to take the model, I think, that's been developed so far which reflects a lot of things that have happened and try to address some of the comments that all three of us and others may have had with regard to the challenges that are upcoming, because I think frankly those are the most important ones.

A couple of compliments. This isn't a critique so much as a set of observations. I think EIA does deserve some significant analytical credit for what's happened so far, the reflection on the ability to analyze and deal with and understand DSM, to look at it fully integrate or more effectively integrate, in any event, newer technologies and their penetration into the business; to handle some class of risks, and I think there's more to be done in this area that's very, very important in the industry as it affects the industry's decision-making; the idea of more fully integrating supply, demand, and other resources; the idea of more fully integrating and giving you the potential to deal with environmental challenges. I think all of that are sections of the models that EIA has put a great deal of effort in and deserves credit. A lot of it is really pretty reflective of what's going on in the state of the art.

The challenges and opportunities remain, however, and some of those Marty Baughman in particular ticked off in some very detailed ways and neither John nor I want to repeat that. I think there are a number of areas, as John alluded to, where at a larger level there are some issues that should be rethought or thought as you move forward into some of your analyses. I'm going to pick on a couple of them because I think they're not susceptible to easy solutions.

One of the speakers in the renewable section said that it's not nice to critique something without offering a solution. We're a research institute. We're working on the solutions. We don't know the answers either. I think they're important ones in coping with the capability you're trying to create in the model.

First observation about challenges and problems that remain goes to regionality. The model deals with large regions. This is an industry that's rapidly differentiating. Somebody described it or characterized it as looking a lot like the big bang. Yes, we use the same technologies. Yes, we use the same network. No, no two companies have the same market structure or business strategy. Decision-making looks very different and it's not obvious that large regions work very effectively. I'm not sure they ever did. I think they'll work a lot less effectively in the future than they have in the past.

The model uses tight pools. Those tight pools in many ways do not really reflect well the way the industry operates. We've looked, for example, at natural gas based technologies. You miss some of the graininess of the way those technologies work, their cost structure, their operating characteristics with large type pools. Diversity is important in the industry. To the extent that we wash away some of the diversity and local characteristics, you lose everything from the peaking character of the business. You lose things like some technologies like natural gas. Some of the fuel characteristics are in fact likely to be misrepresented by too large a regional choice. We can see this in some of the larger pooled utilities in the industry already.

The model uses -- in the same large region characteristic, it uses regional load duration curves, the LDCs. That misses the diversity that exists in the industry. That diversity is becoming more and more important in a competitive less regulated environment because the way we manage the retail business is likely to change. To the extent we can't capture the way the industry is making decisions, particularly at the retail level, we're going to miss technologies. We're going to miss costs. We're going to miss environmental implications.

If you think of the model and its likely uses for more than sheer aggregate forecasting, it's important to be able to capture some of those characteristics. DSM and local generation in particular, I think, are likely to be misunderstood. To the extent they're captured well in the model, they're going to be misunderstood even more by missing those low duration curve characteristics and differences.

The model also remains, second point, principally a bulk power, wholesale market-focused model. It focuses on capacity and energy, not entirely but largely. That misses some of the things commented on by Marty earlier and misses some of the VAR support and other such things, but it misses the retail side of the business. As we change our regulatory and market structure, I think, like telecommunications and other industries, it's going to be in that part of the business that we see many of our most dramatic changes. And also, that's going to be the part of the industry where some of the most important technological changes occur.

We miss, for example, customer and market and competitive characteristics in areas that are important to the business if we focus solely on the bulk power characteristics. We think in terms of the model in terms of system reliability. As everybody in the business knows as a planner, it isn't the system that fails. It's the mice and the trees and the squirrels and all those other things. It's local reliability that matters. As we try to provide quality service to customers, we're going to be looking for things that affect local customer service and quality and reliability. That will lead us to some technologies that a focus on capacity and energy alone are going to miss.

Again, I think a lot of the points that all of us are making are going to go not so much to the technical structure of the model alone. A few years ago, that technical structure probably was a better representation than it is as we look out. It's to the fact that your timing is such that the changing of the industry is really going to ask you to do a few things somewhat differently.

Three things you can think of immediately. One is the IPP affiliated power producer EWG environment that John and Marty both spoke to. The reality is that the decision criteria used in that rapidly emerging piece of the business, the part of the business that's going to be the wholesale part, are likely to be rather different, I suspect, than what we've represented in the model to date. I think it's important to go back, get better information about those decision criteria. They will be evolving. What we see today isn't going to be even a good representation of where we are five years from now or more. I think we need to reflect that development more in the bulk power part of the modeling system.

The second point dealing with the change part of the business goes to the competitive response. One of the things we've been thinking about in the retail part of the business is, as a response to competition, the development of what people have called "differentiated" or "tailored" services. That's a very important concept because it goes to the point that John Hughes was making.

As industries have undergone deregulation, they've found themselves having to move away from a skewed biased cross-subsidized rate structure into something much more tailored to individual customers, particularly those individual customers with choices. You can think immediately of large commercial and industrial customers as examples of that, what John does for a living.

There's a value focus that's beginning to develop in the marketplace just as it did in telecommunications. Pricing will be differentiated to reflect that value focus, also services and the kinds of services we begin to develop and put into the marketplace, even who does the development of those services. That's a value focus, not a cost focus, and that's an important distinction. This is still very much a cost driven-modeling system.

If you think about the impact on prices that Marty raised, those prices may not be sustainable in a marketplace for some customers because of the value issues that they raise. As we start differentiating services and start thinking about services, we have to think about the relationship between pricing and value.

Finally, if we remain in a slow growth environment in this differentiating marketplace, there's another element that's missing and that's the focus on T&D. If you look at the model as a capacity model and an energy model, it misses the T&D opportunities and the T&D issues entirely because of the nature of its focus. There is a transmission section in there. There are wheeling issues in there. That's not the issue that I'm concerned about.

What I'm concerned about is the relationship between capacity and energy on the one hand at the system level and what we invest in and put in place to operate the retail business as it is tied in with T&D management on the other. The things that are going to get undervalued if we don't properly reflect T&D costs and T&D services and T&D growth in the modeling system are things like distributed resources, things like peaking generation, things like differentiated services which have characteristics very different from DSM to the customers.

I think it's important to be able to capture in some way -- and in a very large regional modeling system this is going to be a very, very difficult challenge -- to capture the role of T&D more effectively in the business. T&D management as part of retail business management I think is going to be an important part of the industry's future. I think somehow or another we have to find a way to get that graininess back into the system. To the extent we don't, we're going to be undervaluing some of the options and therefore misstating some of the costs and challenges. I wouldn't want to isolate this to renewable resources that we talked about earlier in the session just before this. I'd isolate it, rather than to renewables, to that entire class of distributed resources, both generation and demand management.

A couple of quick examples of what some of these issues really mean. For example, the role of markets in T&D, the retail business focus. If you think about aging T&D resources, the higher rate of growth in T&D investment compared to generation investment going on in the industry in recent years and likely into the future for a number of years, the fact that local growth distorts what's happening on the distribution system and the subtransmission system, what we're seeing is a shifting in the industry's cost structure. The industry will deal with that as it deals with the retail business, by looking very differently than it has in the past to T&D.

In the past we've treated T&D in the context of generation planning plus area support and I think really the model reflects that kind of logic. What we're moving to, and you can see this in many utilities today and certainly in EPRI's work, is a refocus that tries to wed T&D investments and T&D management as a source not only of T&D cost management efforts and quality improvement efforts, but at the same time, as for example the distributed generating system supplies local area benefits, it also has capacity and energy benefits. That turns out to be important.

In the first place, as you look across any given utility system, its load duration curves for its feeders, if you will, or its substations are very diverse. Some of them are terrible. Some of them are merely bad. What you look at is the opportunity to improve asset utilization by providing a distributed resource, say a generating resource, anything from a gen set to a fuel cell that not only provides capacity and energy benefits exactly the same as the benefits at the system level, but also T&D enhancements and benefits as well. In some areas, those benefits are going to be worth precisely zero. In others that we've seen, those values are going to be quite large.

The model structure today, I believe, will undervalue and in fact not value at all most of those resources. As the market differentiates itself, our suspicion is that those are going to turn out to be very important resources as we look at the increments of generation that are coming on, not existing base, so we're going to tend to undervalue some of the services.

At the same time, there's another issue that you can think about in a technical context. What the model is really doing is looking at produced costs, capacity and energy costs. It's not looking at delivered costs. Another way of looking at it, and maybe this will help in the analytical effort, is to think about the delivered cost of power to different load centers. If you do that, what you suddenly recognize is that moderate cost technologies can beat out low cost technologies. I don't think the model will reflect that right now. I think that's at least a good part of the point and may be a hint at how to go and deal with this.

The other final area I'd like to touch on, again echoing back to some things that both Marty and John said, goes to the industry structure, goes to the IPP affiliated power producer, EWG sets of issues combined with a retail focus. The issue really is who makes a decision and how do you reflect that in the modeling that you do? Right now you have a market sharing mechanism between IPPs, for example, nonutilities and electric utilities that I think pretty much reflects where we are right now. I don't think it does a very good job, and Marty spoke to the need to really go back, as I believe EIA already is, and really look hard at the nonutility model.

I think we need to understand what the decision criteria are more effectively of the IPP EWG environment. There's a good likelihood -- we don't know how it's all going to work out, but there's a good likelihood that in the future bulk power wholesale resources are going to come from an EWG IPP kind of environment. Retail resources, be they distributed generation, gen sets, fuel cells and the like, peakers, maybe some classes of storage are likely to be served by a retail business unit or a retail distribution structure of a utility. Those decision rules aren't the same. I think we need to understand them and understand them in a different way as business decisions than we have in the past.

Just as some examples, I think we tend to understate, given our current structure and look at the nonutility generator decision rule that's in the model, I think we tend to understate the kinds of technologies they're likely to invest in. There is some evidence to indicate that, at least to some extent, a nonutility, an IPP investor is looking at a different cash flow, a different set of return decisions, rate of return decisions than a utility. It may be quite easily more willing to adopt and advanced technology simply if it can expedite the speed of payments coming back to it.

If I can get licensing over with more quickly through an environmental control technology such as selective catalytic reduction, even though I don't need to do it to meet standards, I might well adopt that technology. That doesn't show up very well in the model, that kind of thinking; however, it works out in reality. I think you need the flexibility in the tools you're developing to reflect that.

Keeping in mind time, let me close with those two basic kinds of observations. I think there are some structural things you need to think about in the industry and I think there are some modeling regional characteristic issues that are going to be hard to get around and are in addition to the detailed observations that Marty made, but I think they underlie a whole lot of what we've all been talking about.

Congratulations to EIA, I think, are really due in what you've accomplished so far. I think the challenges are quite strong as you look out at capturing some of the things we've all commented on.

Thank you very much.

MR. BEAMON: Again I want to thank all the reviewers. I wrote down more notes than I think we had in the CDR. It'll take some time to go over.

One thing that was clear from everybody's comments was that we perhaps need to look at the model structure so that it's more forward-looking and more flexible, and we'll attempt to do that.

And we also, as they all recognize that the industry at this time is undergoing an awful lot of change. It's going to be difficult to develop a model that can capture all this, but we should attempt where possible to build in the flexibility to do so.

Given the amount of time we have left, right now we want to entertain any questions from you all for either us or for the reviewers.

Questions? Please come up to the mike and identify yourself and your affiliation so that we can have that for the record?

MR. MACK: My name is Steve Mack from Energetics and I just have a couple of operational questions. One is about the market sharing algorithm. It seems to me that when you do that kind of sensitivity analysis it's only really accurate around your original optimal basis and I'm wondering if perhaps you've thought about just after you've run the market share algorithm, just to use those results to establish lower bounds for the variables that you want to replace.

MR. JONES: We are considering something along those lines. Depending on how much it does alter the solution, we may have to rerun it through the LP where we do impose the market share as bounds because if we do change capacity choice decisions, for one thing, it could affect the environmental compliance decisions. So, we're going to have to look into see just how much perturbation on the solution it does result in, but that is one option that we are consideration.

MR. MACK: Right. And just one follow-up question now. One of the big knocks against goal programming is the fact that people have serious questions about how the coefficients were generated for the objective function. I'm just wondering if perhaps you have investigated some of the newer techniques for judgmental modeling like perhaps classic utility theorem might be the only process to generate this coefficient.

MR. JONES: Well, at the present time, we're not planning on using the goal program for the modeling structure. Certainly the use of the LP doesn't preclude future use of a goal program, if that's the direction we choose to go. But since we're not at this point looking into using the goal program, we haven't done any investigation in terms of looking at that.

MR. MACK: Thank you.

MR. BUTLER: My name is Jack Butler from Argonne National Laboratories.

My question relates to the nature of your user interfaces. One of the goals of the program is to provide a tool for the analysis of various policy options. Since the range of policy situations that users may potentially want to evaluate using the model. Could you describe the sort of interface, the nature of the user interface and how this will -- how the model will be available to an outside user? Will the user have to go into the source code and alter the source code or will there be screens that the user can put in various inputs and be returned various outputs?

MR. BEAMON: At this point our current schedule calls for us to complete this module sometime in April and to begin testing and integrating all the various submodules. Then the first time that the models will be available to the public is in October of this year. However, I doubt even at that time that we'll have a very elaborate user interface. We're working on that and our plan is in the longrun to make many of these modules available in PC versions or work station versions with the interfaces that allow you to modify just the type of things that you were talking about, perhaps different parameters for technology cost and performance characteristics and other variables such as that. But at this point we haven't spent an awful lot of time putting those together. We're still building the core of the model first.

MR. BUTLER: Thank you.

MS. SULZBERGER: Virginia Sulzberger with the North American Electric Reliability Council.

One of the basic assumptions in your capacity expansion model is the words you used, "the minimum reliability requirements." How do you determine those for a particular region and how do you set up what those targets should be for each of the NERC regions?

MR. BEAMON: Most likely we're going to rely on a lot of the material that we get from your organization to set perhaps minimum reserve requirements and standards such as those. There's not going to be a ioss of load probability developed internal to the model. We're going to simply have to put those in exogenously based on NERC requirements.

MR. BERNOW: Steve Bernow, Tellus Institute. I had, I guess, a related question.

In the first presentation, there was a list of characteristics of the modeling in which both minimum reliability and capacity requirements were stated. I was wondering the same, whether that was, in fact, redundant and you were going just with capacity requirements as opposed to reliability targets. If you were, how would the model take account of the reliability benefits of different resource options? For example, the distributed dispersed renewables.

MR. BEAMON: As many of the commenters brought up, we're going to have to look a lot more at the distributed utility concept because as we've designed the model right now, we're not dealing with that explicitly and we may have to come up with some methodology for incorporating that. We're not dealing with it at this point, but many of the people have brought that up as an issue we need to look at.

MR. BERNOW: Could I ask another question?

MR. BEAMON: Sure.

MR. BERNOW: Again in the first presentation there was some illusion made to combining the loads of different years in a way that would depart from straight averaging which flattens things out. Could you describe how that would be done?

MR. JONES: Well, essentially, if you had the loads available for several years, typically we get -- and I think we have as many as eight years and sometimes more characteristics. If you took the 8,760 hours, excluding leap years and things like that, one method that has been done in the past is just simply average the loads for January 1, 1:00 in the morning, whatever, and come up with one curve that has 8,760 hours. That does the effect of smoothing it. I was talking about you're going to lower the peak and raise the base by doing that. If you had, say, five, eight years of data or whatever, you could compile a -- you could also have all of that data. So you had 8 times 8,760 hours and you derived your load curves from that. You would capture the actual peak, but the duration of that peak would be much lower than if you had the lower peak, but it would be for a larger number of hours. So, it's one attempt that we're doing to capture more of the actual extremes in load as opposed to the strict averaging.

MR. BEAMON: Any other questions?

MR. LAUGHLIN: Keith Laughlin, House Science Committee.

Could you please describe the process by which you're going to determine the cost and performance data for various technologies that will be then input into the system?

MR. BEAMON: At this point right now, we're trying to develop a database for all of the cost and performance characteristics for the various generating technologies and we're essentially reviewing all of the various sources of such data. At this point it's kind of in the beginnings and we've gotten some of the technologies in that and we're going to be circulating that for review as that comes out to try to see if we can't get some sort of consensus or at least some sort of reasonableness approach to all those. We may also look at some of the potential learning curve impacts and other factors that might be relevant to new technologies.

MR. MUELLER: This is another one of those questions I think is an important one to bring out here where there's not only the cost and performance characteristics in an engineering economic sense, but it goes back to some of the comments that some of the reviewers were making. It also goes to the decision criteria, the evaluation criteria of the investor. If you look solely at the engineering economics fuel characteristics, whatever, of the technology, you get one answer. If you look at how that technology fits into the business of the investor, it can look quite different. If you think of an IPP project as made up of, for example, a fuel supplier, a vendor supplier and somebody else, the numbers if you look, for example, at the returns or the costs as characterized by the use of, for example, a gas pipeline system that the vendor owns, those costs or those investment characteristics change. I think a database, and we deal with this at EPRI in our technology assessment information. I think that the costs that go into the database and then flow into the model need to be modified in some way to reflect those kinds of characteristics. Not just of the technology, but of the technology project partnership. I think that's an important characteristic of some of these technologies.

MR. BEAMON: Other questions?

MR. ALTBERGER: Paul Altberger, Gas Research Institute.

Are you dealing explicitly with repowering within the model structure? And as a second question, how are you dealing with dispatch from the cogeneration side?

MR. JONES: Within the phase one development of the NEMS, we're not really going to be dealing much with repowering because it's so incredibly site specific. We're going to have to probably do a little bit more research in terms of how to try to link it to our model. We do recognize its importance and it's something that we're looking at, but we're not very far along in terms of how we're going to attack that at this point.

The actual treatment of dispatching cogeneration, as I mentioned before the actual cogeneration is going to take place within the demand models. What we're attempting to do though is build the load curves from actual applications. Aggregate them up from sector and even subsector usage so that it's particularly important with respect to DSM to do it that way. So, we can potentially alter the sector-specific load curves as opposed to the total load curve to represent the contributions from cogenerators within that sector.

MR. BEAMON: Other questions?

Thank you all for coming. We have a lot of comments to look over.