THE NEMS CONFERENCE

ELECTRICITY OPERATIONS PANEL

February 2, 1993 - 8:30 am

PANELISTS:

Robert T. Eynon, Moderator
Jeffrey Jones, Presenter
Roger Naill, Reviewer
Vance Mullis, Reviewer
Larry Makovich, Reviewer

AUDIENCE PARTICIPANTS:

Scott Rogers
Gary Miller
Paul Holtberg
Virginia Sulzberger
Thomas Petersik
Christian Demeter

EIA

PROCEEDINGS

MR. EYNON: Good morning. Welcome to the panel on electricity operations. This is the second of three sessions dealing with electricity and the electricity market module in the National Energy Modeling System.

I'm Bob Eynon and I am responsible for nuclear and electricity analysis in the EIA.

In our session yesterday, we heard about capacity planning. For those of you who are interested, we have revised handouts from Marty Baughman that are available in the back of the room that you can pick up on your way out. Those revisions incorporate comments from the Economics Committee of Edison Electric Institute in their meeting last week in Phoenix.

I would like to acknowledge the contributions of a number of people there who participated in that review. John Harris from Carolina Power and Light Company did an extensive review of the CDRs. I also want to thank Steve Hiebsch who is the chairman of the committee, and also David Townley of Southern Company Services, Inc. I also would like to acknowledge the efforts of Russell Tucker, who is the EEI representative to that committee. I think they all strengthened the review of Marty Baughman through their interactions.

In this session today, we're going to be dealing with electricity operations. Jeff Jones who was the speaker yesterday is also going to present the results today. We'll follow the same format. We'll have three commenters and then we'll open up to questions from the audience.

With that, I'd like to turn it over to Jeff Jones.

MR. JONES: I'll be talking to you today about the Electricity Fuel Dispatch Submodule, or the EFD. I'm sure you've gotten your share of acronyms since you've been here, and you'll probably get a few more today. But if I use EFD, I'll be referring to the Electricity Fuel Dispatch Submodule of the Electricity Market Module of the National Energy Modeling System.

This is an overview of the Electricity Market Module, the six major submodules of the model. There is the Electricity Transmission and Trade Submodule which will be providing the level of the inter-regional trade to the Electricity Fuel Dispatch Submodule which it will incorporate in its decision- making.

The Load and Demand-Side Management Submodule will be deriving load duration curves that will be adjusted for the level of demand-side management programs as well as contributions from intermittent, renewable energy sources.

The Non-utility Generator Submodule will be providing operating characteristics of independent power producers and exempt wholesale generators to the Electricity Fuel Dispatch Submodule.

The Electricity Capacity Planning Submodule was discussed yesterday. For those of you who weren't there, it will essentially be providing the level of available capacity, taking into

Electricity Operations
in the
National Energy Modeling System

Jeffrey Jones

Energy Information Administration

EIA

February 2, 1993

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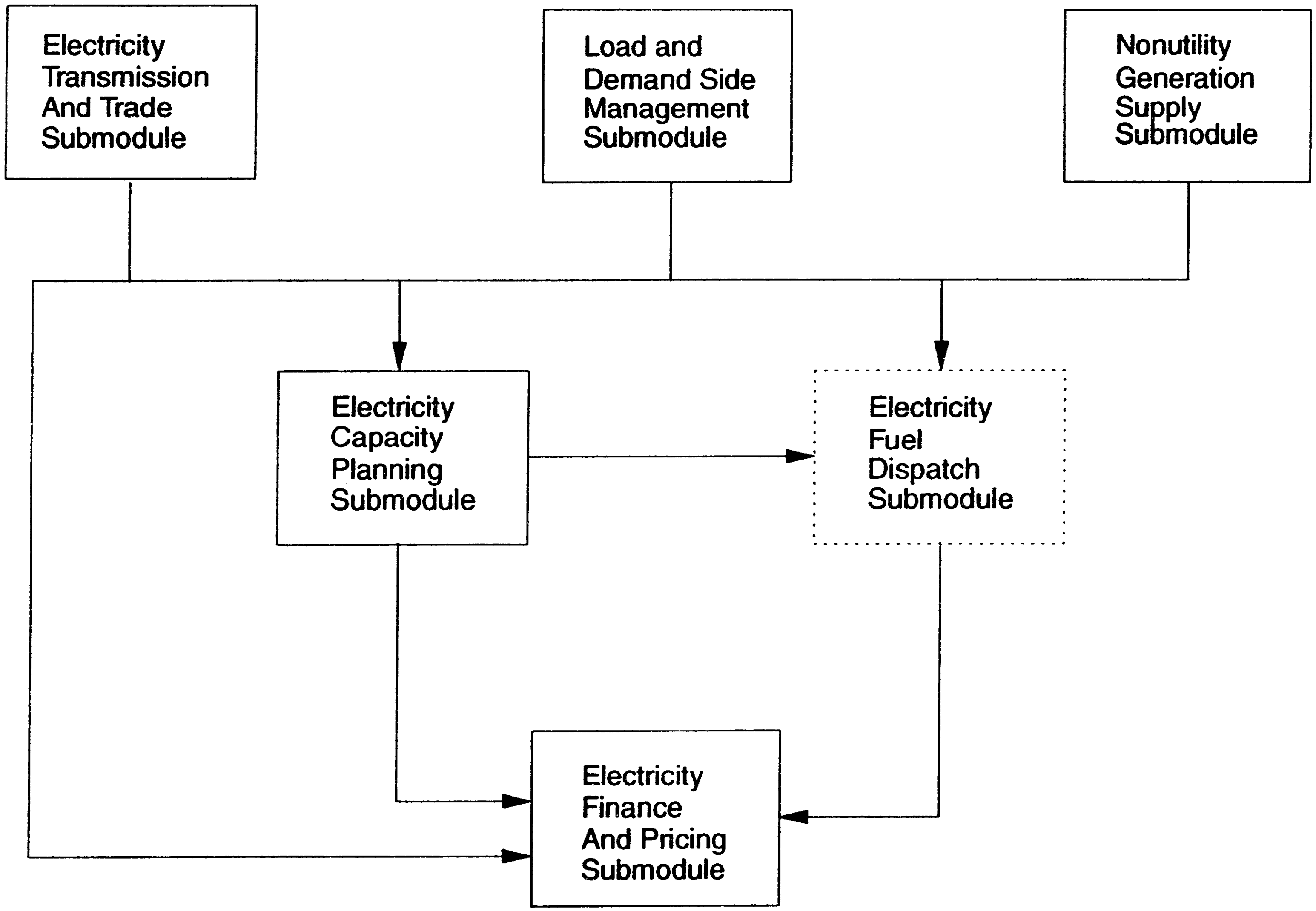
Information Flow Within the Electricity Market Module



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account existing capacity, retirements, planned additions, as well as additions that are determined by the capacity planning module to be necessary to meet the growth in demand. It will also be providing the amount of capacity that has pollution control equipment installed, which will be used in some of the decisions by the Electricity Fuel Dispatch Submodule.

The EFD also receives some key inputs from modules within NEMS, but that are outside of the EMM. The major inputs from other modules are the electricity demands, the annual demands for electricity that are provided by the end use demand modules and the fossil fuel prices, which are provided by the respective fuel supply modules within the NEMS.

The major outputs of the EFD are primarily the generation and fuel consumption by fuel type, which are also passed to the fuel supply modules so that they can evaluate the fuel prices that are consistent with those demands. The EFD also provides the variable operating cost, the fuel and variable O&M cost to the Electricity Finance and Pricing Submodule, which it uses when it determines the price of electricity.

There were several objectives that we were seeking to achieve when we were designing the EFD. In our previous modeling efforts, the regional aggregation that we used was basically used for all of the different energy sources and it was Federal Regions. And that was basically a collection of states, for those of you who aren't familiar with the definition of Federal Regions. And it's really not particularly appropriate for how electric utilities operate.

We've chosen to use a representation based on the North American Electric Reliability Council or NERC regions, and we've split some of the larger regions into sub-regions to give us a little better handle on that. I think some of the reviewers will indicate they think we need to split it even further, but this is what we have done at this point in time. And we feel that this more closely approximates the way electric utilities operate and will enable us to do a better job of representing electric utility operations.

We also are endogenously representing the Clean Air Act Amendments of 1990. In our previous efforts, we exogenously determined the compliance strategies and fed them in as inputs, and they weren't part of the internal decision-making process. We also are including the flexibility to incorporate other environmental legislation as it arises or as policy analysis is required. For instance, there could be a cap on carbon emissions as well as energy taxes, which are being batted around pretty furiously around town right now. It's something else we would also be able to accommodate within this structure.

The main logic behind the algorithm itself is to operate the available generating units in a least-cost manner, subject to any emissions restrictions or requirements that are required either by current laws or laws that we would be examining. We intend to dispatch both utility-owned and non-utility power plants. We also are planning to incorporate the utilization of renewable technologies along with the non-renewable. That's also an improvement and an enhancement over our previous modeling efforts. We basically determined the renewable supplies in the current modeling system exogenously, and then decremented the required contributions from non-utility supplies.

Along with the renewables, there are both dispatchable and intermittent renewable

Statement of Purpose

- Use 13 North American Electric Reliability Council (NERC) Regions And Subregions Plus Alaska and Hawaii
- Represent the Clean Air Act Amendments of 1990
- Accomodate Other Environmental Regulations (e.g. carbon)
- Dispatch (Operate) Generating Units on a Least-Cost Basis, Subject to Emissions Limits
- Dispatch Both Utility And Nonutility Powerplants
- Determine Supply for Nonrenewable and Renewable Technologies
- Incorporate Intermittent Technologies and Demand-Side Management
- Account for Electricity Trade

technologies, and we do intend to explicitly represent contributions from intermittent technologies, as well as demand side management programs. And finally, within the context of the Electricity Market Module, we plan to account for inter-regional electricity trade.

Just a few points on the selection of the electricity supply regions, of which there's a total of 13, plus Alaska and Hawaii. Again, we feel that it more closely represents the operations of electric utilities as they're currently configured. It allows us to use the actual load data without having to configure it to a regional aggregation that doesn't lend itself very well. It also gives us a more meaningful representation of inter-regional transfers.

Census Divisions, which is sort of a general level of aggregation for the NEMS model, or the Federal Regions are both based on combinations of states. Since many electric utilities operate across state lines, what we were finding was that in some cases, we had artificial inter-regional transfers that simply occurred because the utility operations crossed state lines and it wasn't truly an inter-regional transfer. We feel that this should hopefully go a long way towards curing that problem.

The one additional burden it does place on us is that since the electricity supply regions have little or no meaning to any of the other modules, a lot of the inputs and outputs in the communication with other parts of the NEMS model do not occur at this regional aggregation. So, we're going to have to transfer data between different regional aggregations in order to perform the necessary linkages with other components of the model.

Most of you probably are familiar with the Clean Air Act Amendments of 1990, but this slide just provides a little summary of some of the basic requirements that we're having to incorporate because of the regulation. Essentially, there's a national SO_2 emission constraint that we're incorporating in the model. The legislation itself actually allocates allowances to individual units.

However, since trading of emission allowances between utilities is allowed according to the legislation -- and actually, probably even encouraged is a more accurate word -- it actually translates to a national level constraint since the allowances can be traded anywhere within the United States. Because of that provision, we also have to represent the trading of allowances among utilities and within the current modeling context, we're just representing inter-regional allowance trades. We're not doing intra-regional allowance trades.

The EFD will only be dealing with the short-term compliance options. Those are primarily environmental dispatching in which you may decrease the utilization rate of a particular unit or collection of units that has a higher emission rate, and increase the utilization rate of a particular type that has lower emission rates, as well as fuel switching within a particular unit to go from a higher sulphur fuel to a lower sulphur fuel.

The longer-term strategies such as installing scrubbers on existing units basically were considered a decision for the planning component. It involves a significant capital investment, and it also requires a considerable period of time -- potentially, on the order of a few years --to actually complete the installation of the control equipment. We felt that was better suited for a decision in the planning component. However, the decisions from the planning component are

Electricity Supply Regions

- Represents Service Territories of Integrated Utility Systems

- Allows Representation of Demand Using Actual Load Data

- Allows Meaningful Representation of Interregional Transfers

- Requires Mapping to Other Regional Aggregations (e.g. Census Divisions) for Communication with Other NEMS Modules

Requirements to Incorporate the Provisions of the CAA Amendments of 1990

- National SO2 Emission Allowance Constraints
- Allowance Trading Among Electricity Supply Regions
- Short-Term Emission Reduction Options
  - Environmental Dispatching
  - Fuel Switching
- Long-Term Strategies in Planning Component (e.g. scrubbing)

incorporated into the dispatching decision. So, any prior decisions to scrub will be reflected as available capacity with scrubbers within the dispatching module.

And just one other side note on the planning component. The planning component does contain both a representation of planning and dispatching, so that it compares the trade-off between operating costs and capital expenditures when it's making the decision to install the scrubbers or not.

The representation of demand that we use within the model, as I said before, are annual demands for electricity from the end use demand models. Quite clearly, there are fluctuations in the demand for electricity by season, by time of day, by day of the week. And the annual demand for electricity, we basically need to capture those fluctuations because there are implications for the amount of capacity that's required and the fuels that will be used.

And within the load and demand-side management model, it basically is taking hourly load data that's provided from NERC and that forms the basis of the representation of the demand for electricity. These hourly load requirements are adjusted, prior to being received by the electricity fuel dispatching module and they're adjusted for contributions from demand-side management programs. And one of the things that we're looking at now is trying to sort of dis-aggregate and separate demand- side management programs into those that are essentially at the total control of the operator and would be more consistent with the dispatchable type. Those, we're looking at actually moving within the electricity fuel dispatching sub-module itself.

Other ones that are time dependent such as cycling air conditioners or things like that would be more appropriately dealt with by reducing the requirement for energy supplies at the appropriate time. And we've also planned at this point, to decrement the load requirements for any imported power that is provided.

We are going to be classifying the demands for electricity into seasonal categories. Right now, we're looking at using six periods, six 2-month periods and they simply follow the calendar year. January and February is the first one, and November and December is the last one. We will be creating from the hourly load requirements that are adjusted for the three different categories of demand-side management, inter-regional imported power. We will then be creating load duration curves for each of these six seasonal periods which will then be used as the requirements for generating electricity.

On the supply side, this is a list of the energy sources that we're representing within the model. I don't think there are any major surprises or anything about this. Within the current model, we had a fairly robust, I guess, or wide representation of fossil fuels and uranium. We didn't do, as I mentioned before, a particularly good job of the renewables, and we're making an concerted effort to expand upon that within the NEMS. And as I said, we're doing that endogenously as compared to the exogenous representation that we used in the current modeling system.

Within the grosser categories of coal and oil, we've split it further into sub-categories. There's a couple of reasons motivating us to do this. Number one, there is the requirement to represent the environmental legislation. For instance, the Clear Air Act, just using coal or

Representation of Demand for Electric Power

- Use Hourly Load Data from NERC
- Adjust Hourly Requirements for Generating Capability
    - Demand-Side Management
    - Intermittent Renewables
    - Imported Power
- Use Six Two-Month Periods for Seasonal Variations
- Create Load Duration Curve for Each Seasonal Period

Energy Sources Used for Electricity Production

- Fossil Fuels
  - Coal
  - Petroleum
  - Gas
- Uranium
- Renewable/Other
  - Water
  - Geothermal Steam
  - Sun
  - Wind
  - Wood/Waste

Subcategories for Coal and Oil

- Coal
  - Three Btu Levels (Bituminous, Subbituminous, Lignite)
  - Four Sulfur Classes (pounds of SO2 per million Btu)
    - Low Sulfur — $SO2 \leq 1.2$
    - Medium Sulfur — $1.2 < SO2 \leq 2.5$
    - High Sulfur — $2.5 < SO2 \leq 3.34$
    - Very High Sulfur — $SO2 > 3.34$
- Petroleum Products
  - Low Sulfur Residual Fuel Oil ($\leq$ 1.0 percent sulfur)
  - High Sulfur Residual Fuel Oil (> 1.0 percent sulfur)
  - Distillate Fuel Oil

just using oil just doesn't give us a sufficient handle on how to represent the fuel switching.

So, we've broken this into four different sulfur categories. The 1.2, which is the upper limit on the first category corresponds to the limit specified by the New Source Performance Standards as well as the phase two limit that's in the Clean Air Act amendments. The upper limit on the medium sulfur category, the 2.5 pounds per million BTU is the phase one limit of the Clean Air Act emissions. And then the upper two categories were basically at the request of the coal module that needed that detail to represent supply in the coal supply module. That's also the logic behind providing the three different BTU levels is to support detail that was required in the coal supply module.

On the oil side, again, it's basically the standard oil products that are primarily used by electric utilities. There's low and high sulfur, residual fuel oil -- and again, that's to help us represent fuel switching to comply with environmental regulations -- and then distillate fuel as well.

This slide basically provides a short overview and it may be somewhat of an over-simplification. But it's just to sort of give you a little bit of a handle on how the algorithm itself works. The first step is to assign an emissions penalty cost. And initially, we set that cost equal to zero for the first go-around.

There are a couple of reasons for that. Number one, if there are no emissions limits -- until 1995 when the phase one of the Clean Air Act goes into place, there is no national level requirement on the emissions. And therefore, we don't need to apply the emissions limit. Even once the limits do go in effect, we start off with a penalty cost of zero so that we can see whether or not compliance can be achieved on a strict economic basis. And if it doesn't, then I'll explain later how we go from there.

The next step is to determine the combined variable cost, that's the combination of the fuel, the variable O&M, and emissions costs. Basically, this allows us to put in a trade-off between the operating cost and the level of emissions that is achieved, based on the fuel that's used. If we have a higher penalty cost, that's going to drive us toward the lower sulfur fuels because you can reduce the combined cost by reducing the emission rate. If you have a relatively low penalty cost, that tends to drive you toward the higher sulfur fuels so that you can take advantage of the relatively low fuel costs that are associated with those.

Once we have these three costs for each of the capacity types, we rank them in ascending order of those costs so that the first plant type in the so-called merit order has the lowest combined cost and the last plant has the highest combined cost. Based on this merit order, we allocate the capacity against the seasonal load curves to meet the demand for electricity. And the logic behind that is so that we use the lowest cost plants the most and the highest cost plants the least.

Once the energy requirements are determined for this particular allocation pattern of the available capacity we determine the resulting generation and fuel consumption. Based on the fuel consumption, we multiply it by the emission rates and determine what the corresponding level of emissions are. Given that level of emissions, we simply compare it to what the

Dispatching Algorithm

- Assign Emissions Penalty Cost
- Determine Variable (Fuel, O&M, Emissions) Cost for Each Capacity Type
- Determine Merit Order (Rank Capacity Types In Ascending Order of Cost)
- Allocate Capacity To Meet Demand Based On Merit Order (Most Economical Type Used Most, Least Economical Type Used Least)
- Determine Generation and Fuel Consumption Corresponding By Capacity Type
- Compute Emissions and Check for Compliance with Emissions Limit
- Determine Allowance Trades

Emissions Penalty Cost

- Describes Marginal Cost of Reducing Emissions through Fuel Switching
- Depends on Low Sulfur Fuel Premiums
- Does Not Represent Cost of Emissions Allowance
    - Fuel Switching
    - Retrofit of Scrubbers on Existing Units
    - Changing Capacity Mix
- Use Separate Penalty Cost for Each Pollutant

emissions limit is. If we happen to over-comply with the emissions limit, then what we do is, we relax the emissions penalty a little bit so that basically, that's going to result in increasing the emissions. If we under-comply with the penalty, we will increase the penalty cost so that we drive the emissions down a little bit. We've incorporated the flexibility to put starting points in for this emissions penalty cost, and as we become a little bit smarter about what level of emissions penalty cost that we're going to be seeing, we have to take advantage of that so that we can speed the turnaround of the model.

Once we've actually achieved the compliance and we're consistent with what the national level constraint is, we determine the inter-regional allowance trades by comparing the allocated allowances against the actual emissions from the model. Then the net gain or loss is either an allowance purchase or an allowance sale.

Basically, I just wanted to make a few comments on what this emissions penalty cost is because as we've talked to certain people and given certain comments, it appears that it does create some confusion as to what it actually is.

In the context that we've implemented it, it really represents the marginal cost of reducing emissions through dispatching options alone, and again, that's primarily through fuel switching. For LP aficionados, if we had a linear programming formulation of electric utility dispatching, it would be analogous to the dual variable on the emissions row.

And the level of that particular emissions penalty that we are going to be seeing is going to be highly dependent on what the low sulphur fuel premiums are. If there is a relatively high premium on switching to a low sulphur fuel, then that's going to drive the emissions penalty cost up. I want to emphasize that it does not represent the cost of an emissions allowance. That can only really be determined in conjunction with all of the compliance options, both planning and dispatching. So that basically has to be determined in conjunction with the planning decisions so that we can incorporate fuel switching, scrubbing and changing the utilization of capacity as well in an integrated decision.

As I mentioned before, we've incorporated the flexibility to examine multiple emissions limits, and in order to do that, we would use a separate penalty cost for each pollutant. We would solve for each of them simultaneously, to achieve compliance for all of the emissions. Depending on what different emissions we were representing, it could turn out to be a mute point. For instance, if we imposed a limit on carbon in addition to the limits on SO_2, it's most likely that the SO_2 limit wouldn't be binding. And therefore, by default, we would only be solving for one, but the flexibility is there to solve for more than one.

At this point, I'd like to turn it over to Bob and he's going to give a discussion on the representation of electricity trade in the electricity market module.

MR. EYNON: One of the other sub-modules that exists within EMM is the Electricity Transmission and Trade Submodule. We have a component design report out on that. I'd like to sketch out for you here, a few details of that effort.

We are planning to have two broad categories of trade that we're trying to capture. The

Representing Electricity Trade

Categories of Trade

- Firm Power Sales (Planning Decision)

  Motivating Factors:

  Diff[illegible]ces in Natural Resources
  Surplus Capacity

- Economy Sales (Dispatching Decision)

  Motivating Factors:

  Load Diversity
  Supply Diversity

Adjustments to Fuel Dispatch Algorithm to Represent Domestic Interregional Economy Trade

- Adjust regional demands to account for known firm power transactions
- Dispatch plants in exporting regions first to determine excess capacity available in each load slice
- Allow excess capacity in exporting regions to be utilized in other regions where economical (including transmission costs)
- Constrain decisions by interregional transmission limits
- Allocate savings from trade between importing and exporting regions

International Economy Sales

- Represented exogenously
- International economy trade driven largely by water conditions in Canada and load diversity between U.S. and Canadian utilities
- "Normal" hydroelectric surplus will be determined
- Load diversity will be derived using National Energy Board (NEB) and EIA data

first is firm power sales. Firm power sales represent dedicated capacity that is available in one region as surplus to satisfy the needs in some adjacent region. Firm power becomes available when a utility either over-builds because the demand is not realized when a new facility comes on line. It also can occur because of differences in natural resources. For example, hydroelectric plants in Quebec are certainly more economic than oil and gas steam plants that might exist in Massachusetts. Hence, the need for firm power.

The second category of trade is called economy sales. This occurs because of differences in the actual operations of utilities due to load diversity. If one region has higher demands than another, a region with lower demands may have excess capacity which can be made available on a short-term basis. In this case, the energy is what's being made available to the purchasing region, not necessarily the capacity. Economy sales usually are not assured, so that at any time, they can be interrupted.

How do we plan to address this? With respect to firm power sales, we will adjust the regional demands in the region that receives firm power to accommodate the power provided by an adjacent region. Our initial efforts will deal only with those regions that historically have engaged in trade. In the first phase of this effort, we will also examine firm capacity that is either currently in operation or is planned. In subsequent versions of this model, we plan to allow the model to decide what transfers of firm power might be possible based on economics. But the initial efforts will only deal with either actual or planned firm power transactions.

With respect to economy sales, we will dispatch plants in a potentially exporting region first, then determine what capacity will be available over and above that region's needs for potential export. Once we've determined that, we will look at each one of the load segments in a potential receiving region and then do some costing to determine whether or not those sales would be economic. In the costing phase of that, we will consider both the transmission costs as well as the losses to get the power to the region that would potentially be purchasing it.

These transfers of economy power will be limited by the available transmission capacity, so that we will not have sales over and above the existing capacity of the system. Later, we will look at the options of building additional transmission capability between regions. With respect to economy sales, the savings that accrue will be split between the purchasing and selling regions.

This effort is designed to address transfers of power that occur between regions, both domestically and internationally. So, we will have both firm and economy sales with both Canada and Mexico. Firm power sales in the international markets will be developed using supply curves of available power from both Canada and Mexico.

With respect to international economy sales, we plan to do those exogenously. We will take a look at historical trade patterns, examining historical water levels that are available using mean conditions, to determine what levels of power would be available on an economy basis from Canada. We will also look at the load diversity that exists in the winter and the summer in Canada and the United States. We plan to use information from the National Energy Board of Canada and the Federal Electricity Commission of Mexico to develop these estimates.

With that as background, I'd like to begin with the comments from our reviewers. Our first speaker is going to be Roger Naill. Roger is responsible for planning at The AES Corporation, an independent power producer. Roger has a great wealth of experience in modeling and analysis, both at the Department of Energy and at Dartmouth. He has a background in both physics and engineering and is well qualified to address this topic.

Roger?

MR. NAILL: Thank you. Thanks, Bob, for inviting me.

I have one slide that I'd like to go over with you that summarizes my comments in an orderly way. Actually, I don't have that much to say about this subject. It's difficult to focus in on one piece of a model, as you can imagine, and try to make comments that make sense in the context of what the overall modelers are trying to do in a model as big as the NEMS System. But I tried to do that anyway.

My first comment is that I have been in the position that they're in -- which is trying to build a model and baring your soul to people before you're actually completed building the model. Please take these comments in a kindly and gentle fashion. You know, I'm very sympathetic to the position you're in -- you are trying to do the best job you can with the resources you have.

I have had some experience with the Energy Information Administration's models and the model's predecessors, and I have drawn on that experience as I read the documents. I've worked with Bob for a number of years and am fairly familiar with the models that they've built. I do get a feel for what this model is trying to do with respect to its predecessors.

I've also been in the position of using these models for policy analysis for the Government, answering questions that might arise having to do with policy (I've worked in the Policy Office at DOE). So, I want to give you my biases about where I'm coming from -- how do I approach this? I have tried to think as a policymaker: Would this model be a useful model for policymakers?

My biggest concern, perhaps, or issue that I might raise with the model, has to do with its use of optimality. My first two bullets in my chart talk about optimal dispatch and least cost compliance plans. They both fall together in one category that says it's really a common structural approach of the model. I believe, however, that it's possible when you're building a model like this to be too optimal. Because from a policymaker's perspective, what you like out of a good policy analysis model is for the model to represent the world in a realistic way, including the problems associated with the world.

If you build a model that's theoretically perfect -- let's say we build the perfect representation of an electricity dispatch system that includes the absolute least cost dispatching algorithms under all conditions we could think of and all assumptions we could think of. That may be an interesting exercise, but it may not be very useful to a policymaker. Because what he wants is a model that describes the problems that the policymaker sees in the world, including all of the world's failures -- market failures, and perhaps in this case since we're talking about

DISPATCH MODELING ISSUES

- optimal dispatch for regions
- "Least Cost" compliance plans
- SO_2 allowance prices
- NUG versus utility costs and performance
- Long-term coal contracts
- Interregional power transactions
- North American Free Trade Agreement (Canadian power)

dispatching, dispatching failures.

So, I tried to think: could this model perhaps over-optimize to the point where the model's dispatching algorithm was essentially solving problems that the world was facing, rather than simulating how the world works, including problems? And there were two on the dispatching side that I thought were at least worth thinking about, Bob. I'm not saying that this is the case or not. It's something to test, really.

The first one is optimal dispatch. It's pretty clear, at least in my experience, that an optimal dispatching algorithm simulates the real world at the utility level. A utility has a finite area that it's obligated to serve, and a control system under its own control. It's actually got a bunch of computers that are doing just what the model is trying to do, which is optimize the use of power generation within a region. But it's not clear when you go to a regional model or a national model whether an optimal or least cost dispatching algorithm really simulates how a system works in aggregate -- the aggregate of a bunch of utility systems in this case. For the nation, it would be 209-plus utility systems (that's just the investor owned systems) and how they would act in aggregate.

For example, in the extreme, you might have a utility that's essentially got all coal resources and a next-door utility that's got, for some reason, all gas resources. And they're both optimally dispatching, but they may not -- when you add them together and look at them as an aggregate whole -- act the same as if the whole system was dispatched as one unit. So, that's at least, an issue to think about.

A suggestion to check this theory is to test the structure of the model against historical behavior. We have done this for our national model and have concluded that optimal dispatch doesn't work. When we tested optimal dispatch against regional or national behavior, one had to add some more constraints to get the model to reproduce history. Mostly, the optimal dispatch algorithm tended to over-use coal resources (which were the least cost resources), and under-use, particularly, the oil-fired resources.

So, what you end up doing in an optimal dispatch model to make it more realistic is to start undoing the optimality. In other words, you're going to have to go in and put constraints on the least cost resource, which might be coal or whatever the marginal cost resource that is the lowest cost, and make the model use in a rather arbitrary way the other resources. So, that's at least something to think about for the dispatching algorithm.

The second consideraton is optimality associated with least cost compliance plans. I notice that you have initiated some modeling of the Clean Air Act and the compliance that's going to have to happen with the Act. There's a rather nice description in your documentation about how compliance can occur -- you can use scrubbers or you can do fuel switching, or you can reuse your resources, essentially re-optimize, for compliance.

Having read news clips in the papers, there seems to be at least some evidence gathering that CAA compliance also will not be optimal. What I'm particularly thinking of is that at least in the midwestern utilities, it looks like there's some sort of an aversion to allowances, is the way I might describe it.

Utilities seem to be reluctant to rely on the allowance market and are more likely in the real world to build a scrubber or switch to low sulfur coal. And it's very regional. It depends on what the indigenous resource is, too. There seems to be a bias towards solving your compliance problem within your own state or region, rather than relying on an allowance market that does a lot of trading between regions. I don't think there's enough evidence yet to know how this is going to work its way out, but it's something, I think, to think about when you're tuning the compliance part of the model.

The third area -- allowance prices -- is an analytically interesting area for me, especially, again, thinking from a policymaker's perspective. It wasn't clear to me how you modelers were going to set the allowance price. Is it exogenous or edogenous? I guess most people model it exogenously -- they just assume an allowance price. However, the EPA and the ICF model, I think, had an endogenous allowance price. In these models, the allowance price was determined by the cost of cleaning up SO_2. You could do that in this model, I think, if you wanted to.

I don't know if you were planning on making the allowance price endogenous, but that would be awfully interesting. It would be very, very interesting -- but perhaps out of the scope of this model. That's a whole modeling effort in itself to focus on the allowance market and look at allowance pricing. I don't think I've ever seen anybody tackle that issue, and it would make for a very interesting paper or piece of work, if you could say something about allowance prices.

People don't even know, frankly, whether allowance prices are going to go up or down in the future (that's how little we know about it). I have my own hypothesis about it because I have a mental model about how that works, but it would be useful to see what a model says.

The fourth area is non-utility generation versus utility costs and performances. This is probably more in the line of an assumption to the model rather than a structural part of the dispatching algorithm. But it's an important area for energy forecasting. Again, exposing my bias, my company is a non-utility generator, so we have a lot of inside knowledge about this industry.

From the perspective of NEMS, the issue is: are you going to set the prices, the costs, and the performance of non-utility generators equal to utilities? Because if you do, I think you're going to miss the boat. In the real world, they are not equal -- the cost and performance of non-utility generators has been significantly lower. In other words, the cost of electricity generated by non-utility generators has been significantly below the so-called "avoided cost" of utilities. That's why non-utility generation has been so successful in penetrating the electricity market. The reasons for this cost difference is a whole other story on its own, but we've done some research and published a paper on the subject. The data is sort of soft, but there is some evidence that that is, in fact, what's happening.

The last subject -- long-term coal contracts -- is a pretty trivial one. It's important that you acknowledge that long-term coal contracts do exist, and take them into effect in your models. I'm sure you're going to take that into account when pricing coal, but that will affect, significantly, how the model is dispatched. And it may look non-optimal again in the sense of, if you look at the spot market, you wonder why utilities are doing what they're doing. It may be because utilities are incurring prices that don't necessarily reflect the so-called market in the short term.

The second to the last issue is inter-regional power transactions. Bob already talked quite a bit about how you're planning to do that. My comment is to suggest that inter-regional transactions may create an overall solution that is perhaps more optimal than a regional optimization. For example, consider the BPA inter-ties -- an inter-tie between the Pacific Northwest Utilities and California which transfers power back and forth between those two regions. Not only do you have regional optimization, but now there are power transactions that allow you to shift economy power between regions (whichever way it goes, it's cheaper). One place (California) peaks in the summer and another place (the Pacific Northwest) peaks in the winter. The power goes back and forth and allows planners to optimize between regions.

And I don't know if you're going to do inter-regional efforts endogenously or exogenously, but this can get pretty complicated when you get into it. When you consider regions, plus you start taking into account actual inter-regional flows, this is a pretty messy and big analytical problem to solve if you tackled the optimality problem.

The final point is the North American Free Trade Agreement -- it really just considers Canadian power. Canadian power is also another sort of sneaky source of power that makes this dispatching problem a little harder to optimize because Canada has sort of reacted to the U.S. market and is trying to be competitive. Pretty clearly, their goal is to undercut the U.S. utilities and sell cheap power down into the U.S. You might want to take that into account too.

And that's pretty much it. Thanks for your attention.

MR. EYNON: Thank you, Roger.

We'll hold questions until the end if that's all right with you.

Our second reviewer is Vance Mullis. Vance is with Southern Company Services, Inc. He's responsible for resource evaluations and decision support at Southern Company. He has a lot of hats that he wears and he's done work in both generation and transmission expansion planning, rate design, competitive bidding, corporate modeling, DSM, and load forecasting. So, he has seen a number of aspects of the modeling activities that we're talking about today.

He's also responsible for the development of EPRI's utility planning model. Vance is an electrical engineer and is a member of the IEEE.

Vance?

MR. MULLIS: I don't want to claim credit for all the utility planning model, just some parts of it.

Thanks, Bob. You have put yourself in a fishbowl and it's a nice thing to do, but it can be uncomfortable.

I've got a general presentation on model design, and then I'll talk about how some of these particular points apply to the model we're looking at today.

Models that try to do everything are going to do some things very poorly. Regional models that don't accurately simulate transmission constraints are going to give misleading results. If I was going into the '90s, I'd be looking at moving away from convolution models, going towards Monte Carlo models. And in general, using industry standard models is a good thing. Finally, you can't throw models at a problem that really needs thought.

Models trying to do everything will do some things very poorly. Production cost models, for example, are very poor reliability models. Who has heard of PRO MOD? Anybody heard of PRO MOD? PRO MOD is a pretty popular production cost model, but it's a lousy reliability model. It's got a line on the report that says "EUE." Some people look at that and not knowing what the model is, don't realize that that's really a worthless number. And the numbers get used because there's a number on the report that says that's what it is. And surely it wouldn't be there if that wasn't a good number.

Regional production cost models also won't predict off systems sales very well because they're not designed to predict off systems sales very well. They're generally designed to predict regional production cost.

Dynamic programming models and other optimization models need a person to help them find their way. That limits their ability to respond to all the changing futures. They're basically person/machine systems. There's not a model you throw all of these combinations in and let the tree diagram run out the dynamics, the dynamic programming, and out pops the answer. Re-powering is a good example. We will probably, with this model, overestimate the cost of continuing to supply electricity through utilities because of things like re-powering, and other places where there are diversity. Where there are things we can do, but we don't see the smaller options because everything is averaged together.

Demand-side and supply side modeling don't fit as well into one model as vendors would lead you to believe. The vendors that tell you their model will do both those will lie about other things also. I've got another blank down there that you can fill in, that blank and blank don't fit in the same model as well as vendors will lead you. You could put in NUGS and traditional utility units because that is much more complex than is being modeled here. And it's true -- I agree with Roger that there's a good bit of difference. I'm not sure if I agree with him on the reason why. NEMS will probably overestimate IPPs because they don't recognize the number of the cost components that are still borne by the utility that would have been borne by the traditional unit.

Regional models that don't look at transmission restraints are going to give misleading results. Now, it's true they're easier to create, but they're going to underestimate production cost. They're going to overestimate sales between neighboring utilities. Just like Roger said, they're going to overestimate low cost fuel use and underestimate that of high cost.

Part of that is because of the infinite tie capacity in the models. And you can assume you can transfer power where it's not physically possible. Secondly is, you get a lot of that in

Factors to Consider: Production Simulation Model Design

* Models trying to do everything will do some things very poorly

* Regional models that do not accurately simulate transmission constraints will give misleading results

* Convolution models should be moving out of favor

* Monte Carlo techniques should be considered for all new production simulation models

* Using industry standard models is a good thing

* You shouldn't throw models at a problem needing thought

Models trying to do everything will do some things very poorly

* Production cost models are poor reliability models

* Dynamic programming and other optimization models need a person to help them find their way, limiting their response to changing futures

* Demand-side and supply-side modelling do not fit into the same model as well as vendors will lead you to believe

* ________________ and ________________ do not fit into the same model as well as vendors will lead you to believe

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__Regional models that do not accurately simulate transmission constraints will give misleading results. They:__

* are easier to create

* underestimate production cost

* overestimate sales between neighboring utilities

* overestimate use of low cost fuels

* underestimate use of high cost fuels

commitment problems where you commit units. They have to run at night, but a model without a commitment algorithm won't see that and that appears to be a fairly substantial flaw here.

The regions are just too big that we have now. Southern TVA and VACAR can not come close to a tight pool. There's no way they can operate like that. That goes from where we stand right now all the way to the Florida Panhandle, and that's not a reasonable size region to get an answer on production cost.

That's for the base case for what's going to happen normally. When you go to a change case -- which is really why we run models to find out differences from one thing to another -- then you don't really know what you've got because you don't know how far off you were to start and you don't know which way the errors went when you made your change case.

Convolution models, well, they should be moving out of favor. They've got their uses. They were more useful before computer power started getting so much cheaper. But they don't commit units well, and they don't handle energy limited resources like HYDRO well at all. And of course, they're hard to explain to people which gives you some credibility problems. And you'll get too much HYDRO shaved off the top in traditional applications, using low duration curves tied with the convolution models.

If I were going into the '90s, I would be looking at Monte Carlo techniques. They're much simpler to visualize. They're more accurate. For production costs, they solve a lot faster than you might think. Maybe a chronological Monte Carlo model might be an appropriate thing for validation here, to run some parallel. You're probably better off aggregating units than regions in models like this. You'd probably get more accuracy. If you're worried about the amount of data you've got to work with, cut back on the number of units and then do some plants combined instead of tieing utilities together that can't be tied.

Using industry standard models is a good thing. Someone has already tried the code and found some of the errors in it. And there will be errors in it. You can get to the point that you need to do a study and it was originally in the design of the program, but nobody has ever ventured into that piece of code before. And you come up with something that "yes, the model has been around a long time, but we've never done that with it."

You don't have to prove your model in every new situation. The load shaping that was talked about yesterday in one of the items, where they before had done some averaging which blanded out the load shape and decreased the peak to valley ratios. There's work that has been done in that in industry on ranked average methods and other approaches that are already sorted out and work well. If you have a problem, you can hire experience because there are other people that know about the models. And you'll have some credibility with the other users and at least they'll know the limitations and you can gain insight from them.

And you can drive changes through data a lot of times because models that tend to be written for multiple users have more switches and more things that are changed through data rather than hard code. Sometimes when you write from scratch, first of all your eyes get too big on what you can do. And secondly, your view of what you're going to need in the future may be a lot more narrowly focused. And you may not realize that this may change down the road.

Convolution models should be moving out of favor

* They were more needed before computing power became cheap

* They do not commit units well

760 * They do not handle energy limited resources well

* Sometimes it is hard to tell if they are making any sense

But they do have their uses.

Monte Carlo techniques should be considered for all new production simulation models

* Much simpler to visualize

* More accurate

* More results are available

* Easy to move to parallel processing

* Much better evaluation of energy-limited resources

Using industry standard models is a good thing

* Someone else has tried the code and found some of the errors already

* You do not have to prove your model in every new situation

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* It is easier to hire experience if it is needed

* You will have some credibility with other users

* Many changes can be driven through data rather than code and this is often less expensive

But it is not always best

And you shouldn't throw models at a problem that needs thought. Sometimes we're too quick to do that. The only purpose in a model is to improve our intuition because all our decisions are made by intuition. We gain our intuition by the sum of our experiences, and what we see out of the models helps us to improve that intuition. You can get a precise answer from a computer that you would have been better just going back and reckoning what it ought to be.

For example, I read a Target reserve margin study from a state in the Midwest that will remain unnamed that said they needed 9 percent reserve margin. And they did a fairly elaborate study with lots of sensitivities and evaluations with some industry-known models. But you can look back and reckon that nine percent is not right. Well, we did a reserve margin study a few years ago in the Southern System and we found that you also needed a 9 percent reserve margin if you ignored any variation in weather -- if you could have weather set and it was always exactly normal.

Well, you know, that's what they did in that study too. And it's amazing the numbers came out exactly the same, but I reckoned they were wrong. And really, I reckoned they probably left out weather, and that's exactly what they did. So, you have to use thought with these things because people will misuse the models. I think especially, maybe, close to the region where we are right now.

So, in summary, the regions are too big. The lack of a commitment algorithm is a problem, and I would prefer to move away from the use of the low duration curves and the convolution techniques. The demand-side is overestimated. Relying solely on the total resource cost test without moderation from the RIM test, and without reviewing the customer value, is going to considerably overestimate the amount of DSM. That's wise to add in this nation.

The averaging, where everything is averaged together, makes the whole system bland and you miss opportunities and you won't get right answers because of that. It's hard to predict which way they go.

The NUGS and the utility interaction are much more complex than have been modeled here and it may be that it needs to be reviewed as to how that's treated completely.

We have a problem in that we only predict things we know in these things, too, and that we don't look, nearly as we should, at the potential for capital substitution. And changes we typically underestimate market forces in these by predicting the only way we can comply forever is with clean air by fuel switching or scrubbing. There's a real high likelihood that somebody will think of something else in the next 20 or 30 years.

And finally, back to the fishbowl comment. There needs to be a detailed validation plan. And that's always a problem when you do something like this because you've really got two choices. You can choose not to validate it and assume it's all right, and you may get by with that for a while. You may not have a warm feeling about it. The alternative is that you may try to validate it and you may find that you have problems. You get a better answer that way, but it can be somewhat embarrassing. So, we need a detailed validation plan here, I believe, before the model will be able to have credibility with the industry. That's all.

<u>Theorem:</u>

<u>You shouldn't throw models at a problem needing thought</u>

Corollary:

764 A precise answer from a computer can be more wrong than a reckoned estimate

MR. EYNON: Thank you, Vance. We appreciate the review.

Our last reviewer this morning is Larry Makovich. Larry is with DRI McGraw-Hill, where he is senior energy economist. He is responsible for electricity market analysis there. He does forecasting and analysis work. Larry has also been an instructor for managerial economics and is currently pursuing a Ph.D. in public policy.

Larry?

MR. MAKOVICH: It's a pleasure to be here today. I've been trying to do electricity modelling on a regional basis for many years now. And one of the nice reasons to be here today is that, you know, misery loves company. But having done modeling for many years now, there are some things you learn along the way and those are what I wanted to try to pass along today and try to build upon what Roger and Vance have talked about.

And one thing, the first point that I want to make is that your model will never have enough detail to satisfy everyone. We've heard today, for example, that the NERC regions and even the sub-regions that you've gone to will open you up for a lot of criticism. My point is, I think using the NERC level is a great improvement over what you had been doing on the federal regions. I mean, I think it's an enormous advance.

I deal with this same kind of problem. I had some of our consultants who deal with our utility clients come in to me last week. They said, "Gee, I want to know, how does your model address retail wheeling?" You know, there's just always a question that's beyond the grain of your model. And what you have to be careful of is, even though you've got, I think, a very solid specification and design here, in the maintenance mode as you go through time, people are always going to be tacking on pieces to this model. And you have to be very careful that you don't let it get big and unwieldy. And then, it's time to start all over again.

One thing that has come up here today that was a point I wanted to make is, there really is a very important algorithm that needs to be thought through here that prepares data going into this dispatch model. And that is, how you're grouping the units together into these aggregated unit groups that you're dispatching. And you had a list in the component report that's a little bit different from the energy sources list you had up here today.

My point is, make an algorithm that allows that to be flexible. Already today, one issue has come up here. This issue of will non-utilities operate differently from utilities? So, if you aggregate together all coal units of a particular type, but you haven't differentiated by ownership, it may, in fact, be the case that for policy analysis, it's important to take into account the fact that the non-utilities might have higher availability, might have lower operating costs. Or the opposite may be true.

But there will always be issues like this, particularly on the environmental side -- technology-driven issues -- where to be responsive, the most important thing is going to be to be able to go back and re-aggregate those units up, you know, creating these different distinctions. And if you've got a flexible algorithm that allows you to do that, it goes a long

Electricity Fuel Dispatch

A Review of the Component Design Report

Prepared by:

Larry Makovich
Principal
DRI/McGraw-Hill Energy Research Group

National Energy Modeling System (NEMS) Conference
February 2, 1993
Crystal City Marriott, Crystal City, Virginia

Overview

- Model will never satisfy everyones demand for detail
  - Always remember speed and detail trade-off
  - Avoid model structures that outstrip available data
- Unit grouping algorithm is a critical issue
  - Create flexible grouping algorithm
- Quarterly frequency adds considerable simulation power over annual dispatch
- Backcasting should be an integral part of model development and maintenance
  - Best performamce measure of model
  - Calebration avoids step-off problems between history and the first year of forecast
  - Most recent past is always a mix of preliminary, final and estimated data

Regional Dispatch Issues

- NERC regions and sub-regions are appropriate analytical areas
- Noncontiguous region should be added to cover entire U.S.
- Power Flows between NERC regions are Important
- NERC to Census mapping algorithm is a complex problem: Do not rely upon historical shares!
- Mapping algorithm accuracy depends critically upon unit aggregations used in dispatch modeling

Incremental Generating Costs

- Add algorithm to generating dispatch model
- Key variable for:
  - DSM economics
  - Cogeneration avoided costs
  - Inter-regional bulk power flows
  - Explaining simulation results
  - Market based electricity pricing
  - On/Off peak pricing

Environmental Dispatch

- Emissions penalty cost is a weak approach
- Foresight Issue: Appropriate compliance strategy investments
- Emission penalty cost or CO_2 tax impact will depend upon unit grouping algorithm
- Emission penalty cost will not approximate the market price of an SO_2 allowance credit
  - With heuristic approach appropriate foresight will lead to a zero emission penalty cost
  - In LP approach, if SO_2 is a non-binding constraint then shadow price will be zero

way in making this model capable to answer a lot of policy questions that come down the road.

The six period dispatch, the two-month periods, one point. In reading the original spec, I thought a quarterly frequency was perfectly adequate, and actually, was going to add a lot of power. I'm not sure -- you know, you're incurring a big cost in going from, say, three seasons to six. I'm not sure how much benefit you actually gain by doing that.

Another point that I could not over-emphasize is that backcasting should be an integral part of your model development and maintenance. And this actually goes to Roger's and Vance's points that these optimization models, you don't want a model that tells you how the world ought to look today rather than the way it does look. And it's true, there are lots of constraints, transmission being among them, that are things you're never going to be able to explicitly take into account here.

So, the approach that you've talked about, the heuristic approach, that gives you some ways to represent these types of constraints and you work hard to calibrate to history, to backcast history, so that you're sure you've taken -- you're not going to have this step-off problem that all of a sudden you forecast next year and you've got enormous changes between your last year of history and your first year of forecast. And it's because you've created a world that is as maybe we'd all like it to be rather than the way it is. The best way around that is to work very hard at backcasting. It sets you up to learn where these constraints are as well as give your forecast a lot of credibility.

The other issue that was brought up, but not really in a lot of detail, concerned moving back and forth between the NERC regions and your federal or Census regions. And this was a problem that we had to tackle about four or five years ago when we first introduced our NERC region-based analysis. And bridging over is actually the easy end of it. We do a lot of analysis of sales and then we create a model that links output at a NERC region to sales at a Census region. And the coefficients, you can judge reasonableness if they represent reasonable loss factors and so forth.

So, bridging over to estimate output by NERC regions, so peak and output by NERC region is not hard. What is hard is coming back. Having done your dispatch analysis at a NERC region or sub-region as you're suggesting and trying to get good estimates of fuel consumption at your Census region.

Don't rely on historical shares. What we have done is continued to track all capacity, both existing and what we add in the model, by both a NERC locator as well as a Census locator. Having estimated utilization on a NERC region, you just have to sum that array across the other dimension and you can get your Census. Again, here, your algorithm that allows you to differentiate technologies at unit aggregation helps a lot in making that accuracy when you're going from the NERC regions back to the Census. So, it plays in there as well.

I didn't see much discussion about the actual algorithm for your incremental generating costs, but that of course, is one of the most important outputs of this part of the model. I guess the only thing I wanted to emphasize there, it's very important that it be based upon the incremental generating costs of both the utilities and the non-utilities that are being dispatched here, particularly as we're trying to do policy analysis of more competitive market structures and outcomes in the industry.

As far as the environmental dispatch goes, we have actually done a lot of work in this area of trying to forecast emissions allowances. And what you're proposing here with this emissions penalty cost, for a lot of reasons, it strikes me as -- you're putting a lot of emphasis in an area that is probably not worth all that much work. The reason I say that on the SO_2 is, it really is much more of a foresight issue. If you assume, as I do, that utilities have got a pretty good fix on what they're going to do for phase one and they will have a good fix, you know, as we move out in time to phase two.

The other thing that since you can bank these allowances, utilities are going to over-comply, you know, in order to create this precautionary bank of allowance credits. Because if they're not sure how much they're going to run their coal units in the future, they will have the allowances on hand in order to cover unanticipated increase in coal utilizations. So, this elaborate feedback that you have that will allow the model to come up with an answer, check it against the allowed levels, then iterate in on a solution, is actually a lot of effort to deal with a problem that I'm not sure is going to be there at all. You know, I think it's going to be very reasonable to expect that utilities are going to be able to deal with that uncertainty by just banking the credits. Where it might be useful is to evaluate these other environmental externality charges that people might want to simulate being introduced into the dispatch algorithm. But as far as an SO_2 modeling mechanism, it doesn't seem as if it's really needed.

I did want to caution on using that parameter there, that penalty cost, on the LP approach, the shadow price of that constraint as an indication of the cost of clean-up. If utilities have planned properly in both cases, that will be zero. You know, you'll start off with that parameter at zero if they've made the investment to allow themselves to burn lower sulphur coal or put on the scrubbers. And in the LP, you know, if it's not a binding constraint, your shadow price will be zero. So, it doesn't really represent the marginal cost and it doesn't even really represent -- if it were binding, the marginal cost at the dispatch level because fuel switching involves a significant fixed cost in the investment to make that happen. So, I'd caution you very much on using that means to deal with the SO_2 question.

And on the non-utility dispatch, one thing that I'm anticipating is because of the way some of the power purchase contracts, many of the power purchase contracts, have been written, there are minimum take provisions from non-utilities. I would recommend that you try to incorporate some kind of a must run specification on some of these non-utilities to reflect that. Because I do expect in the future, there will be some kind of take or pay problems that will crop up with regard to non-utilities, and that you will want to reflect, again, this non-optimal impact on dispatch that will arise from these kind of contract problems.

And finally, it wasn't clear to me where, exactly, the heat rates were coming from when you're translating the dispatch into your fuel demands. It's important that these heat rates come out of an algorithm that is taking into account trends that are occurring from aging, trends that are occurring from the Clean Air Act strategies, and also, trends in heat rates that are occurring from re-powering. R&L Assists of the Future indicates that re-powering is going to become more and more of a dominant issue in utility forecasting. One of the big impacts here is the way it changes heat rates within the industry, and you don't need much of a change at all in the heat rate to really move your fuel demands around. So, this is an area, really, to concentrate on as well.

MR. EYNON: Before we open the floor for questions, I thought Jeff might want to have the opportunity here to respond to some of the many, many suggestions that we've gotten. So, we'll initiate it that way.

MR. JONES: I can come back to the podium with a target on my chest now. I think one thing that's clear from most of the comments is, I think they feel we need a bigger model, in some cases, a much bigger model.

And I think we recognize the dangers of aggregation and that there is a tendency to over-optimize. I think we plan to take care to try to examine just what that is going to be doing to our results. Part of the exercise in the development of NEMS which is not contained in any of component design reports or any of that, is a fairly rigorous validation exercise, including backcasting and things like that. I think during the course of that, we will make an effort to evaluate what is happening to the representation as a result of the aggregation that we're doing. And hopefully, we can then expand upon the representation, identifying where additional constraints such as some of the reviewers said, are needed to be imposed so that we can do a better job. I just want to stress that a validation effort is a part of this exercise, and the model by definition of EIA, can not be used until this validation effort has been completed.

Again, as I stressed, the SO_2 emissions penalty that we're using is not to be interpreted as the cost of the allowance. I think at this point, it's not clear how those allowances are actually going to be priced. It's merely a mechanism, at this point, that we are using to achieve compliance within the dispatching option.

And just to counter Larry a bit, it will not be zero unless dispatching options are not required at all to achieve compliance. If all of the compliance is met through scrubbing options or planning decisions in which you're not going to have to do any fuel switching, then it would be zero if you don't have to do any fuel switching. But if there is fuel switching required, there will be a positive penalty cost. And again, that's not to be interpreted as the cost of the allowance. It's just it will be a non-zero penalty cost.

I think the reviewers made a lot of good points. I just want to stress that it is not feasible for us to build a unit level national model. If that were our charter, we could probably just wait for 2015 to happen and we wouldn't have to look for the results in a model because it would take that long for it to execute. But I don't want to make light of their comments because they made a lot of good points. I believe we intend to try to recognize the strengths and weaknesses that they've pointed out and build to the extent that we can, build them into our model.

We may have some flexibility to include more regional definitions where we don't have that flexibility. We do have a fairly wider disaggregation of the available plants within the model. We're not just dispatching one coal plant within a particular region.

As Larry suggested, we should identify the plants by NERC region and Census region.

Non-Utility Dispatch

- Minimum utilization needs to be insured to reflect power purchase contract constraints
- Cogeneration ought to be linked to process steam requirements
- EWGs as price takers- link to incremental generation costs

Merit Ordering for Dispatch

- Unit grouping algorithm is key to accurate results
- Heat rates ought to be endogenous
  - Related to utilization
  - Trended for aging
  - Adjusted for CAAA strategies and repowering gains

As a matter of fact, we are doing that. We are categorizing the plants within the regions according to the specific fuel region that's most appropriate to that. If, for instance, we receive oil prices by Census division, we categorize the oil plants as one subdivision according to which Census division within that NERC region. So, I think it's a very good idea that Larry brought up and it's one that we have considered and are already implementing within the model.

Transmission constraints seemed to be one common theme that was brought up by the reviewers. We do recognize that that is a very important consideration in the electrical utility industry today. We are making strides to try to represent some of that, but are we going to be able to represent individual transmission flows? I don't think we are. And I think one of the points that came out of some of the reviewers is, it's important to emphasize just what this model can do and what it can not do, and not attempt to try to use it for something that it's just not capable of doing. I think that's, you know, a point that can't be emphasized too much. It's something that, I think, we recognize and we appreciate them emphasizing that to us.

I think one thing that was not brought out potentially in the talk, and maybe not enough in the component design reports, is that we are differentiating between the non-utility sources and the utility sources to the extent that the data is available. And I'm not sure what extent that will be, but to the extent that it is, we will attempt to categorize the non-utility sources according to the contract structures and to the characteristics that are appropriate to that particular entity.

We are not treating them identically to utilities and they are dispatched separately from utilities, using separate characteristics from the utilities. And again, I think our problem is more going to be on the data, not only on the actual but being able to model them.

On the comment from Vance that we potentially shouldn't be modeling them within the same framework, it obviously does create problems, but I'm not sure how we can evaluate them without competing them directly against one another. The same, I think, goes with DSM. I'm not sure how you can evaluate the contributions of DSM, recognizing he's absolutely right that there are limits on the penetration. But I'm not sure how you can recognize the contributions within those limits without competing them against the alternative sources.

I probably didn't do a very good job addressing their comments because they had numerous comments that were very, very appropriate. But those were just a few comments that I had in response to what they said. Thank you.

MR. EYNON: Thank you, Jeff. I would like to add one postscript to Jeff's initial response to the validation efforts.

EIA has a modeling standard in place which requires documentation of all models prior to their use for analysis. In response to that standard, we are developing these component design reports which will serve as part of the documentation.

There will be a second formal report, a model developer's report, for the Electricity Market Module in which these validation exercises will be done. We will not only do the backcasting kinds of activities to understand whether the results of the model are reasonable, but we're also testing the range over which this model can be exercised in order to give reasonable results.

This is a new standard in EIA and we're not really sure how we're going to address it exactly. So, we would invite comments or suggestions from anyone here as to how we might go about doing that. But it is important to note that that exercise will be done before the model is used for any kind of analysis.

With that in mind, I'd like to open it up to questions from the audience for either Jeff or any of the reviewers. I would ask you to use the microphone when you have a question. To give your name and your affiliation, so we can get it for the proceedings.

Scott?

MR. ROGERS: Scott Rogers, University of Toronto. I have a question for Vance about the production costing models being poor reliability models.

Could you tell me which attribute of reliability you're referring to? And secondly, in what types of systems are they reasonably good and which types of systems are they not very good?

MR. MULLIS: If it's a pure thermal system with no devices that have restrictions on how they can operate, and you model the full 8,760 hours or those hours that you expect to be close to having a problem, and if you incorporate the range of weather and load uncertainty that you would expect to see in a probability distribution manner, then you can get reasonably good answers for production cost and reliability, if you treat the commitment algorithm also exactly -- if you treat the commitment algorithm very carefully.

Now, all those caveats are a very, very small world. Dispatchers operate differently in a reliability mode. Our dispatchers, for example, don't run the HYDRO unless -- they run the HYDRO normally for energy. But if they have a problem that they need to hold the HYDRO back for, they'll run CTs before that, you know, what they consider out of economics. They have a dynamic commitment algorithm, basically, to do that.

So, there are so many things that you have to do to make a production cost model a reliability model that it requires a lot of thought and care in the data going into it.

MR. ROGERS: Which measure of reliability are you referring to?

MR. MULLIS: Expect unserved energy, loss of load hours, loss of load probability. To me, they're all tied.

MR. MILLER: I'm Gary Miller with Edison Electric Institute. I have a very basic question for Mr. Jones.

I may have missed something, but it wasn't clear to me how your model will actually be used in the real world by utilities. Will you just, for instance, make it available for purchase on a voluntary basis, by utilities or groups of inter-connected utilities which would like to try to use it?

MR. JONES: As with any model, once it's completed and all the testing has been completed and everything, it's available to anybody in the public. The utilities, non-utilities, anybody can make a request to obtain the model. I personally can't answer how the utilities will use it, but they have the option to use it if they so desire, as well as any person.

MR. EYNON: Paul?

MR. HOLTBERG: Yes, Paul Holtberg, Gas Research Institute. I've got a question, I guess, for Roger and Vance. You both cited the fact that NUGS are different. It sounds a lot like the old, you know, the rich are different statement.

Other than financing differences, Roger, I'm curious why NUGS are different and do you think that they'll remain different than central utilities in the future with all the changes we're seeing in the electric utility industry today?

MR. NAILL: The simple answer is competition. Our experience has been that non-utility generators have a profit motive and are therefore incentivized to cut costs whereas utilities, because of rate regulation, don't. Utilities can pass through costs. That's the simple answer.

Competition leads to a lot of creative thinking in terms of technology choice, risk taking, operation of plant, cutting O&M costs, choice of fuels, and all the way down the line on all the cost components of how you generate electricity. This is creating a lot of very interesting new opportunities in electric generation options.

I think it's true that utilities are reacting to this in some interesting ways. But I think maybe that if there was regulatory reform to create some incentive to cut units on the utility's side, it would be helpful. Given my theory anyway about the reason for cost-cutting, utilities need to be incentivized, I think, to compete. They don't have any incentive now, really.

Utilities are responding -- there's no question about it. There's no inherent reason why utilities can't cut costs as aggressively as non-utilities do also if we change the structure of the industry. And the industry structure is changing. That would be the leading indicator that I would look at: what's the structure of the industry at any point in time and who's incentivized to cut costs?

MR. MULLIS: I'll respond too. There may be a couple of reasons why Roger says that they're lower than avoided cost to the generating units that utilities build.

One of those reasons is that there's an inherent conservatism in the utility business that has been developed over years of regulation. And a lot of times their estimates of avoided costs are high. That's especially a problem in the demand-side evaluations. You look at utilities that are predicting the cost of new combustion turbines. The ones that are avoiding them completely may have a considerably higher estimate than those that are actually building the units.

There's also a good bit of risk shifting that hasn't been recognized and is not well understood by the utility commissions, from the IPP to the utility. And that's a cost to the utility and it's reflected where they're leaning on the good credit in their contract of the utility. So, those are ways it's different.

Plus, in the utility business, the people that build and operate power plants have had some power overtime. And if you talk bad about the power plants, it's like talking bad about their children. You don't want to do that. So, what happens is, things can get added into the design of the power plants that may end up not getting -- some of the options may not get as close to scrutiny on a cost benefit analysis as they need.

Well, that's changing with the IPPs, because if an engineering organization designs its plants in such a way that they don't get the business, then those differences won't stay. And you'll find that the utilities will alter the way they build the plants in some aspects of it to come up with a lower cost. And in large part, they'll just recognize that they don't need that level of conservatism in the price if they're going to do a self-built option.

So, I think that things are going to change and I think they're changing all around now with the utilities now being able to do affiliate transactions. When we get back to a project financed or a fair area on the financing, I think we'll find the utilities, if they want to, can compete very effectively.

MR. EYNON: Virginia?

MS. SULZBERGER: Thank you. Thanks, Bob.

Virginia Sulzberger with the North American Electric Reliability Council.

I think two of the comments, one from Roger and Vance, on validation of the model is very important, and I think you probably want to validate the model in some respect. And I think Roger mentioned looking at a historical perspective. Certainly, EIA probably has more data on production costs and fuel costs that were used by the utilities than the utilities themselves, historically on a macro basis.

But you also might want to try using this model for a particular area or region of the country, and use your dispatch model against what the utilities are doing now themselves, with their own production costing models, where they are recognizing, you know, the effects of the environment and that sort of thing. And look at their environmental dispatch versus yours as a forward look, as well as a backward look.

Another comment I'd like to make, if I may, is whether you're doing the capacity planning module or this dispatch module, I think the thing that's missing in all of this is the fact that everyone is trying to optimize economics. I think the difference is, when you're not a utility and you're trying to optimize economics, you're not doing it under the same constraints. Utilities are optimizing economics under their reliability criteria and constraints.

They're expanding their capacity under their reliability criteria and constraints and they're dispatching generation the same way. When you talk about transmission constraints and limitations, and it's not only for purchases between systems. It's the day-to-day operation where you go off economic dispatch because your system can not take the next single contingency. You lose one more line and the whole East Coast goes down. So, you re-dispatch your generation so you'll be able to take that next worse contingency. And that's what's missing from your day-to-day and hour-to-hour operations.

So, I think that you have to optimize economics, but you do it under the reliability constraints. And I think now you have another set of constraints, the utilities. Reliability and the environment, and then you optimize the system for economics. I think that's what's missing from some of these models.

MR. EYNON: Other comments or questions?

Tom?

MR. PETERSIK: Thank you.

I'm Tom Petersik with EIA.

Going back to the NUG and utility change over time. It seems like, I think, Vance and Roger both referred to that. Given that people think it is occurring and will occur, how do you address it in the modeling?

Roger and Vance, I'm sorry.

Either of you. You've got two different views of the world, or we say that utilities are operating differently than non-utilities and that they will change. So, how do you address that change in the modeling?

MR. NAILL: Well, the way we did it in ours was, you separate the two types by ownership and you just put in different assumptions for cost and performance for the two --

MR. PETERSIK: And leave them that way over the period?

MR. NAILL: Well, that's a good question. What do you do over time? That's a very good question.

I agree with Vance's comments that utilities are changing. You really need to make a judgment about how the industry structure is going to behave over time. You need to assume if we're going to complete the deregulation of generation in this country over the next 10 or 20 years, and to build that into your scenario. And then, I think that would give you a rationalization to change the model's parameters and represent a truly competitive situation in the far future.

But if you assume that we're going to have a utility sector that continues to be regulated on the basis of rate base, and a non-utility sector that's going to be incentivized, I think you'd have some justification to leave the cost parameters alone, leave them different.

MR. MULLIS: I think you're not going to see the big cost differences between the two. I think a lot of that has been financing, and some of it has been very poor scoring systems developed by utilities, that essentially eliminated a lot of things that should have been considered.

You know, if you go through and review the literature on the scoring systems for competitive bidding, it's one nightmare after another. I think there's enough evidence in the literature now that the utilities that go out for bids, and Southern is in the process of going out for bid, aren't going to be as unsophisticated, is the nice way to put it, in their evaluation scores. And I think those costs will move real close together.

Plus, there's a lot of literature on how the banks are going to be requiring more equity in the IPPs, and they're not going to be able to flaunt their financing assets or edge as well. And the costs will move together. And from a global model review, then it ends up not making a whole lot of difference. Because frankly, the performance shouldn't be that much different. I mean, these are standard units they're building. The ones our system are building are the same basic machines that IPPs are going to build. It's not a question of "do they run a lot better?" So, it's not as important that they be separated, I don't think, in the long-term because they'll move together.

MR. MAKOVICH: When we put our forecast together on this, we're closer to what Vance's vision of the future is, I think, than Roger's. You know, if you look at the advantages a utility has in building a new power plant versus a NUG, utilities are much bigger than even your even your biggest non-utility. They've got, you know, a much better access to capital markets.

Many of them have inventoried sites. They've got power plants where they could add more units at sites, which gives them a cost advantage on adding a next unit if they have to compete against a Greenfield unit someplace on a NUG. And as we are seeing, the capital markets are disciplining utilities who have a very high reliance on IPPs because the power purchase contract which allows the non-utility to go in and get the financing, is interpreted as a -- you know, if that's an asset to the NUG, it's a liability to the utility.

And when this risk transfer gets all sorted out, you're going to see the non-utilities getting larger and starting to look like utilities through mergers. And as the risk transfer gets sorted out, we're going to have to have more equity position with these non-utilities. I think as we move out through time, you're going to see within five to ten years, some non-utilities that are as big as their average utility counterpart. And when you look at their capital structure, it's going to be very similar but I think there is something to this incentive difference.

But I think that what it will do is, it will tend to make the utilities reduce costs to meet the competition so that, you know -- they're going to become similar by both moving towards a middle. And that's what we've assumed when we go out in the future to model it.

MR. DEMETER: Yes, Christian Demeter from Antares Group.

With Roger Naill on the panel, I can't resist the opportunity to ask a little bit about the future of FOSSIL2. And with validation being a concern, I was wondering if there would be any use in setting up some parallel scenarios between NEMS and the FOSSIL2 model -- which has been tested and used quite a bit, and we know a lot about the behavior -- and running the two out and seeing what kind of differences there might be and whether you can gain some information in that kind of a scenario?

MR. NAILL: Yes, we changed the name of it. It's called IDEAS now.

You know, the model that Christian is referring to is a model that was built for the policy office and it's really a lot smaller than NEMS will be. It's scope of use and purpose are a lot more narrow than the NEMS. It's focused on a national energy policy planning for the National Energy Plan. It was built for that reason and it's been used that way for 10 years. NEMS, I think, can do a lot more things. It's like a car with a lot more options on it.

In both the FOSSIL2 and newly called IDEAS model, we spent a lot of time trying to, as we say, "calibrate" to EIA. So, I'm sure we'll be doing a lot of new calibration runs, at least for the Policy Office. We almost always are requested to calibrate to the base case of the NEMS model. We're asked to use the same planning assumptions as EIA and it gives an immediate basis for comparison to do at least one case with the same planning assumptions. We almost always do that.

I don't think EIA will ever calibrate to our assumptions -- there's no need to do that. I think that we'll probably show you output that gives you a direct comparison any time that we run the IDEAS model.

MR. EYNON: Other questions?

Virginia?

MS. SULZBERGER: I guess this is a question for Larry.

You said in one of your earlier comments that doing this dispatch and modeling on a NERC level is a great improvement. This is a great improvement over what?

What I'm asking is, if you have smaller models in smaller areas of the system and you're modeling those, and you're really simulating what's going on in the real world versus a regional model where you're doing dispatch for a system does not exist where you can't get generation from point A to point B, why is that an improvement? What are you trying to represent, or what is the problem you're trying to solve?

MR. MAKOVICH: Okay. My comment was the move to these NERC regions and sub-regions, given these limitations that have been brought up, is still an enormous improvement over a policy model that was based upon these federal regions or Census regions which are simply aggregations of states that have nothing to do, whatsoever, with any kind of transmission interconnections.

Look at the data on power flows within NERC regions and look at power flows between NERC regions. It's very clear that if you have to make distinct regional electricity markets, these NERC regions and sub-regions are, I think, a good relevant market to start to analyze. You know, you've got ten times the power flows within them than you do between.

That's not the case with these kind of state aggregations. And in fact, I remember, you know, several years ago there was a study that was done at the Kennedy School of Government at Harvard which had looked on a state-by-state basis at peaks versus capacity, and so forth. You know, it was one of the early studies that created that whole idea that we were facing this tremendous capacity shortage in this country, which was going to lead to these rolling black-outs that would be going on this year and last, and so forth. And the major reason they were wrong was because of the geographic area they selected.

I think that the NERC regions are very appropriate regions. I actually think they will have good luck when they get to the validation -- not luck, but they will have success when they get to the validation point and run this model, I think they will do a good job of tracking changes that have occurred in fuels demand because of the dispatch, you know, by analyzing this at a NERC region. I think that when you compare that to any other kind of nodel -- like next year is going to be what happened last year plus two percent. You know, kind of a REMA-based model or a gut feel model or something. This NERC-base model will give you a fairly powerful tool to analyze supply and demand balance as well as fuel consumption.

So, I think they will have success in the validation stage. And I think, particularly as we move to more competitive markets, these NERC region base analyses become more and more important.

MR. MULLIS: If I could comment on that, too?

The regions are too big. They're not going to give an accurate estimate.

MR. EYNON: I think Paul was next.

MR. HOLTBERG: Roger made an interesting point before that, you know, particularly with electric utility models, we tend to over-optimize. The world doesn't really work like that, you know. It's a Milton Freedman point of view where, you know, asked why his models didn't represent what was going on in the world said, "well, my models are right and the world is wrong." That doesn't work very well.

I'm curious. I mean, other than what you've said before, which you're going to be very careful in looking at the outputs, how are you going to deal with this? It's really an issue of uncertainty in terms of the utility decision making. And Monte Carlo is one way to deal with that production uncertainty, but how are you going to deal with it within a smaller structure? You need something better than just saying, "I'm going to look at the outputs real carefully."

MR. JONES: It's a little difficult to answer that until we know how the model's not performing well in terms of what actual strategies we'll take to try to correct that.

I differentiate the uncertainty phase a little bit, if I'm understanding how you use uncertainty, from actual performance of the model. From a dispatching viewpoint, given that you're determining how the available capacity is going to be used in the current year, I'm not sure uncertainty plays that much of a role in that part.

I mean, all I can basically say is, in terms of evaluating how well the model is performing, I mean, they're absolutely right that we're probably going to have to build in additional detail and additional structure to try to represent some of these things. I can't say, "yes, we're going to do A, B, C, and D," until I know how the model is not performing well. And that's where some of these validation exercises, I think, are going to be important.

I'd also want to stress that if you do a good job backcasting, that doesn't necessarily mean you're going to do a good job of forecasting. But at the same time, that is going to be one of the efforts that we're using to try to evaluate how well the model is performing. We may have to go to a further subdivision at the regions as Vance suggests. We may be able to build in some sort of additional constraints which accommodate some of the weaknesses. But I really can't give you a definite answer until we really know where we stand.

On the issue of uncertainty, the whole issue of uncertainty from the standpoint of the entire NEMS model, is something we're trying to grasp with at this point. All I can say is that we're, you know, looking into the subject in terms of what are appropriate ways of dealing with uncertainty within the model. And again, I know it's not satisfactory, but I really don't have the answer as to how we're going to do that.

MR. EYNON: Scott, you had a question?

MR. ROGERS: I really just have two comments on the last discussion. Scott Rogers, University of Toronto.

We have a model of the NPCC which looks at on a power pool basis. And it reproduces the imports and exports as published by NERC, within a reasonable degree. So, it is possible at that level. Whether it's possible in the inter-NERC region is an open question, but it is possible to go above the power pool level and get results which are reasonably close to those that are being reported.

The second thing I guess I should comment, as the only Canadian here, on Roger's comment about cheap Canadian power. At the moment in Canada, the policy is, if there is excess capacity, then we sell it on a split saving basis. Or if it's larger amounts, then something related to the variable cost difference.

The only two provinces that are willing to build capacity for it are Manitoba and Quebec, and the problem there is that their demand growth is low relative to the size of the HYDRO sites. It takes roughly 10 to 15 years for their demand growth to use up a HYDRO site, so they will sell it on a contract for 10 years at the cost of building the site earlier, basically the capital cost earlier. And that's what the New York contract is about, so that's basically the situation.

MR. MULLIS: It seems it would be a lot easier to get good transfers between regions in a stored commodity than in one that is instantaneous. If you got HYDRO behind the dam and can delay moving it from one region to another, it's a whole lot different than electricity you're generating for use right then.

MR. EYNON: Before we close this session, I'd like to return to a topic that we discussed yesterday briefly here. We talked a little bit about new technologies. I'd like to point out that we have a component design report which we are preparing, describing how we will implement new technologies in our planning component.

The thrust of that CDR is to address three main issues. The first of which is to create a database in which all of the technologies are laid out on a comparable basis. That is, the common components are costed appropriately, contingency is addressed uniformly, and that there's essentially, a consistency across the database.

The second thrust of that is to eliminate technological optimism. The approach that we're taking for dealing with technological optimism is to apply Ed Merrow's work that was done at Rand Corporation some years ago to address the level of the design itself, whether the design of the new technology is fairly far along or whether it's in initial stages. Also, the amount of departure from current technology will also be considered. We will use Merrow's work as an adjustment to the cost to eliminate technological optimism.

The third effort is the notion of learning by doing. And that is, we will attempt to adjust the cost and performance of new technologies based on where they are in the marketplace. That will also rely on historical information that Merrow has done.

We're also attempting to address risk in new technologies. There are risks associated with long lead time projects. There's also risk associated with demand uncertainty. These are two areas that we will attempt to address from a research standpoint. We're not sure how we will be able to address it exactly, but we are looking into it.

Once we have all of this done, we will introduce cost and performance parameters into the capacity planning model and use those estimates for decisions that were described there. I hope that clarifies what we're doing in new technologies.

Given that we've run out of time, I want to express appreciation to the panelists, Roger, Vance, and Larry for their efforts. I think we've had a really stimulating discussion. I look forward to having a continuing dialogue with them and with people in the audience as we continue the development of this model.

Thank you for your attention.