Coal Production Submodule, cont'd.

Limitations

"A third limitation is that the CPS will not be capable of representing the impact of *coal preparation* activities on the cost and quality of coal." - CPS Draft (May 1992), p. 57

• About 45% of U.S. steam coal, and nearly 100% of coking coal, is mechanically cleaned.[1]
• Weight reduction for mechanical cleaning is, in general, around 30%.[2] Sulfur reduction varies.
• 48% of U.S. coal was crushed or screened in 1984.[2]
• Screening separates coal fines from coal lumps. Substantial amount of coal fines are lost in bottom ash or fly ash in stoker boilers.
• Less than 10% of U.S. coal underwent no beneficiation in 1984.[2]
• Capital costs of screening are about $1.75-2.25 per annual ton of throughput.[1]
• Capital costs of washing are in the range of $4-8 per annual ton of throughput.[1]

Sources:

1. The World Bank, China: Efficiency and Environmental Impact of Coal Use, Report No. 8915-CHA, 1991.
2. Energy Information Administration, Coal Data: A Reference, DOE/EIA-0064(85).

Coal Production Submodule, cont'd.

Errors Introduced by Ignoring Coal Preparation

• Volume transported will be overestimated.
• Production cost of coal will be underestimated.
• Environmental impacts of coal will be overestimated, which will create a bias against coal in air pollution scenarios.
• Coal prep is an important third option in the "scrub or switch" decision, much cheaper than scrubbing for small reductions in sulfur.

Other Models with Coal Preparation

• NCM included coal preparation as an optional technology, sandwiched between coal mining and coal transport.
• China Coal Transport Study (CTS) includes coal washing as an option for high ash steam coal, and as a requirement for coking coal.
• Both NCM and CTS are "generalized network" models. NEMS is not.

Modeling Coal Prep in NEMS - General Thoughts

• The Electricity Market Module (EMM), the Refinery Market Module (RMM), and, in some diagrams, the Coal Synthetics Submodule (CSS) are other energy conversion components of NEMS, but coal prep is beneficiation, not conversion.
• Would fit logically as part of CPS, or between CPS and CDS.

Coal Production Submodule, cont'd.

Option A - Exogenous Assumptions in CPS

- Assume historical rates of coal washing by coal type and region.
- Safe to assume that coal preparation takes place at minemouth.
- Advantage - easy to implement, would improve forecasting accuracy.
- Disadvantage - not flexible enough for modeling scrub or switch decisions.

Option B - Develop Supply Curves for Washed Coals in addition to those for Raw Coals in CPS

- Coal preparation decision usually made at same time as decision to build mine, and is usually governed by long-term contracts. Can be bundled with mining decisions.
- An additional control program would be needed so that a single reserve block would not be double-counted.
- Advantage - decision to wash coal will be endogenous.
- Advantage - no new submodule needed, and existing links to other models would be substantively the same.
- Disadvantage - would double the number of coal types for CDS.

Option C - Develop a Coal Preparation Submodule to be Inserted between CPS and CDS

• This would be the recommended modeling strategy only if preparation plants were to be added *after* the mines are built.

• Otherwise, the extra module is not needed, since CDS requires supply curves from CPS as inputs.

Coal Distribution Submodule (CDS)

Purpose

To forecast minimum cost coal distribution:

- quantities of coal produced, by region, mine type, and coal type
- minemouth and delivered prices, by sector and region
- delivered BTU and sulfur content, by demand region and sector
- transport costs, traffic and ton-miles, by mode

And, at the same time, meet:

- NEMS requirements for a simple, fast and transparent model
- non-NEMS requirements to provide detailed reports for important States
- the need to test hypotheses about future transport rate changes between supply and demand regions for individual modes and carriers

And, in doing all this, must take into account the fundamental characteristics of coal markets:

- deposits are widespread and heterogeneous
- demand is widespread, many routes feasible
- contracts (existing and new), supply diversification, & spot market buys
- environmental regulation
- railroad market power

(Source: CDS Draft, April, 1992, pp. 5, 38, 44)

Coal Distribution Submodule (CDS), cont'd.

Discussion Issues

- A tall order...Is it possible?
- What are the major simplifications?
- What is the modeling tradeoff between solution speed, accuracy, and flexibility?
- How is accuracy to be assessed?

Major Simplifications (and Major Concerns about Them)

- O-D rates used instead of a network (ok)
- No endogenous generation of new routes (ok)
- No link-by-link costs (ok)
- Transport cost not sensitive to annual volume or capacity utilization factor (ok- too many commodities to include rail construction, and unit train savings picked up by using O-D rates)
- Arbitrary contract imputation rules (ok)
- Transport rates updating (ok)
- Heuristic algorithm used (ok - proven)
- No bottlenecks (I'm concerned about inland waterway lock capacity)
- Carrier-specific data are not the default option (ok - a necessary simplification, though critical for forecasting at mine, plant, or port level)
- 32 coal types (ok)

Coal Distribution Submodule (CDS), cont'd.

Major Simplifications (and Major Concerns about Them), cont'd.

- 21 demand sectors (ok - maybe even aggregate further, e.g., export and industrial steam and disaggregate in report generation)
- Export demands exogenously assigned to 5 domestic demand regions (Atlantic region is too aggregated)
- 16 supply regions (too aggregated)
- 22 demand regions (too aggregated)

Coal Distribution Submodule (CDS), cont'd.

The Spatial Aggregation Issue

• CDS Report admits that "as the number of origins and destinations decreases, accuracy and stability of inter-regional tonnage-weighted distances diminishes." (p. 16)

• In next paragraph, CDS Report argues that "detail about comparative route geography and link-specific economics ... has few applications in national energy policy analyses addressed by NEMS." (p. 17)

• But regional production levels, inter-regional flows, and mode totals *are listed among the main forecasts to be provided*, and they are effected by aggregation level.

• In my experience with the COLS and the China CTS, spatial aggregation is by far the main calibration issue, and disaggregation is the main solution.

• CDS Report cites an example of the aggregation problem: transport modes for Ohio coal demands. Northern Ohio can be supplied by lake and Southern Ohio by river.

• Ohio is discussed in the context of "imperfect competition" and "non-cost minimizing patterns of supply and demand," but if anything, the Ohio case is *more* competitive than usual because of intermodal competition, and these modes are determinable on a cost-minimizing basis.

Coal Distribution Submodule (CDS), cont'd.

The Spatial Aggregation Issue, cont'd.

- Northern Ohio being served by lake is *not analogous* to importers buying U.S. coal despite it being the highest priced coal on the market.
- All 3 stated purposes of CDS (NEMS needs, non-NEMS needs, and testing hypotheses about transport rates) are compromised by overaggregation.
- Difficult to evaluate slurry pipelines with this level of aggregation.
- This discussion leads to the question of calibration.

Coal Distribution Submodule (CDS), cont'd.

Calibration of the Model

- CDS Report discusses evaluating *uncertainty* in an elaborate fashion, but not *accuracy*.
- Some parameters mentioned for calibration (e.g., adjusting mine prices, or imposing exogenous market share constraints)
- Market share constraints sacrifice the model's flexibility to optimize.
- No mention of calibration procedure or targets.

Incompatible Demands Made on Model

- In my opinion, the goals of much faster solution speed, accuracy of results, and a reasonable amount of flexibility are not compatible.
- Experiments with the stand-alone CDS with varying numbers of nodes could quantify the tradeoffs between speed, accuracy, and flexibility.

Summary

- Major complicating factors for coal distribution are all considered in the CDS Report, and are built into the model, to the extent possible.
- The CDS model is conceptually fine, but would be far more accurate and flexible if used with more origins and destinations.
- The arguments made in the Report to justify the level of spatial aggregation are not convincing.

Coal Synthetic Submodule (CSS)

Purpose

To provide quantities of coal-based synthetic fuels, both liquids and gases, as inputs to the Petroleum Market Module (PMM) and Oil and Gas Market Module (OGMM).

Overview

3-step methodology for each year is appropriate:

1) decision to build synfuels plant
2) decision to continue construction
3) decision to operate

New Builds Decision

- CSS uses a profitability ratio.
- FOSSIL2 model uses Internal Rate of Return.
- Reasons for selecting over profitability ratio over IROR should be explained.

Limitations of the CSS

- None listed!

Coal Synthetic Submodule (CSS), cont'd.

Limit on Number of Synfuels Plants per Region

"The user can set limits on the number of plants which could be built within each region, in total and/or by capacity process type, over the NEMS forecast horizon, determined considering siting factors (availability of water, environmental considerations, etc.)" - CSS (Oct., 1992), p. 34.

Implications

- The maximum number of plants per region is a critical assumption, roughly equivalent to the length of a step on the coal supply curves.
- The Market Penetration Model only applies to the *rate* of introduction, not on the *total* that can be introduced.
- A methodology is needed to estimate these numbers, or else it should be unconstrained.
- It should be mentioned as a source of uncertainty on pp. 62-63.
- Also, the relationship, if any, between this assumption and the Maximum Attainable Market Share (L) in the Mkt. Penetration model is unclear.

Now, from the sources that I could find this seemed to be one of the areas where EIA data are not as good as in other areas. In fact, I think I found this source in a World Bank report -- 45 percent of U.S. steam coal and nearly 100 percent of coking coal is mechanically cleaned.

Now, 45 percent, is very close to 50 percent. How are you going to model it? I mean if you just ignore it, you're ignoring the fact that half is and half isn't.

Is it important? Well, weight reduction for mechanical cleaning is, in general, around 30 percent. I got that from an EIA publication. Sulfur reduction varies depending on the amount of organic or pyritic sulfur in the coal.

Another process is coal crushing or screening. Forty-eight percent of coal was crushed or screened. What that does is to separate the coal fines, the dust from the lumps. We found that was an important issue in China because a lot of the coal fines were being burnt in stoker boilers, and they were simply just either falling through the grate at the bottom or going out the chimney.

And overall, less than ten percent of U.S. coal underwent no beneficiation. Now, this EIA data is from 1984. I couldn't find anything more recent. Maybe I just missed it.

Capital costs of screening are around \$2 an annual ton of throughput. Capital cost of washing could be in the \$4 to \$8 range per annual ton of throughput.

And what's the implication of ignoring this? Well, since there's a lot of weight reduction going on the volume transported will be overestimated in terms of number of ton-miles, which is one of the outputs. The production cost will be underestimated since there's a big cost addition to beneficiate the coal.

The environmental impacts will be overestimated, which will create a bias against coal in the air pollution scenarios because there is some sulfur reduction going on and ash reduction.

Coal preparation is an important third option in the whole scrub-or-switch decision-making. It is a lot cheaper than scrubbing if you just want to make a small reduction in sulfurs. The coal is already pretty good.

Now, this is a graph that we developed not from a national level model, but from a small sample problem, and in it we had utilities in some of the key regions of the country and representative mines with some of the key coal types of the country, and what we did was we put on some of these sulfur constraints on the demand side and looked at how the total delivered costs would go up when coal preparation and FGD were both options and also coal switching. So those were the three choices.

If you look at the curves in general, they all, of course, increase as you tighten the sulfur constraint, but you can also see if you look at point H, the line AHD were the three readings we got when we didn't allow any coal preparation. So I think this is somewhat similar to what you are going to be getting.

REGIONAL ASSESSMENT OF COAL UTILIZATION TECHNOLOGIES USING MATHEMATICAL PROGRAMMING

Samuel J. Ratick and Michael J. Kuby

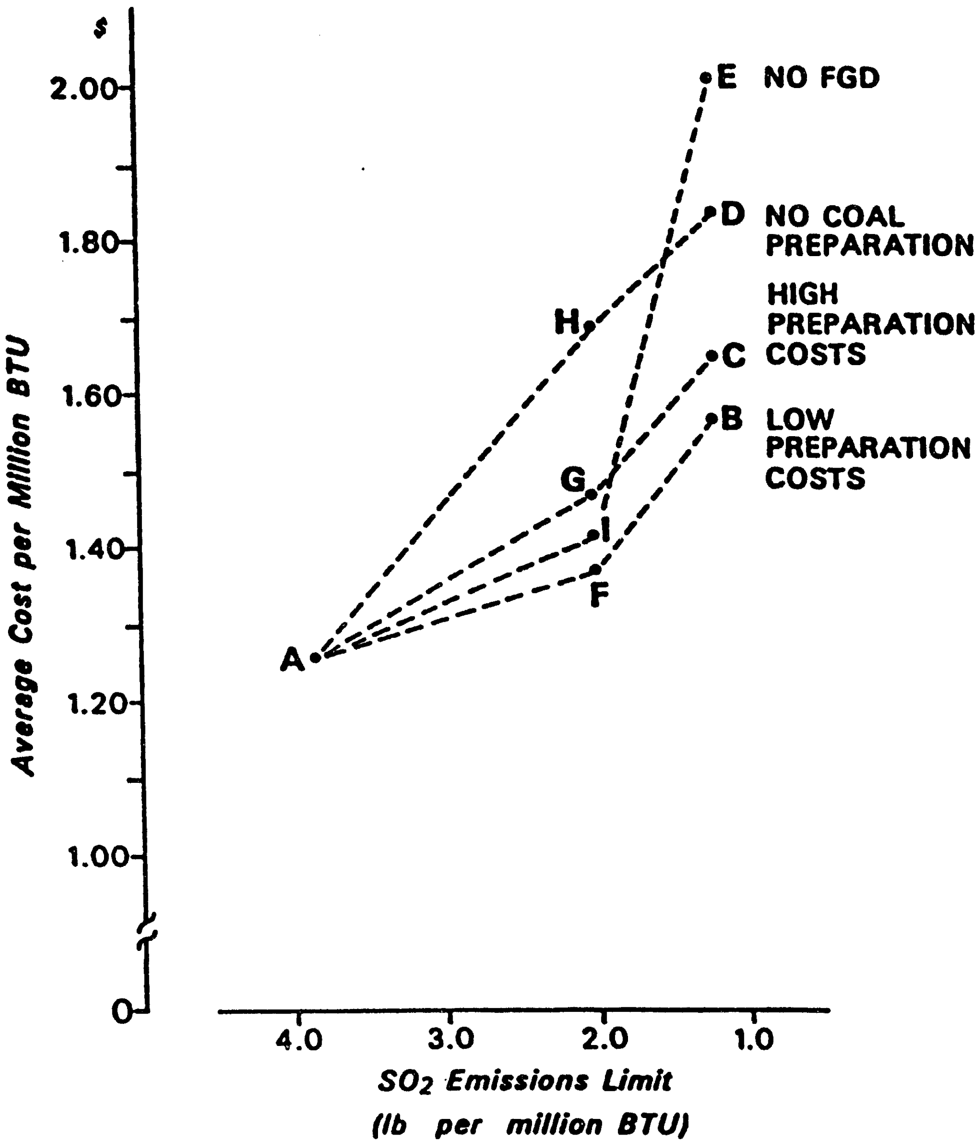

Figure 7. Multiobjective trade-off: cost vs. sulfur emissions.

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And you can see to achieve a sulfur emissions level of two pounds of SO_2 per million Btu, it's very expensive if you leave out coal preparation. That's what point H is showing you. It's higher than G, I and F. You've eliminated a very cost effective, medium sulfur solution.

Now, as you clamp down to say 1.2 pounds per million Btu, FGD becomes a more important factor, but you can see coal preparation is still a part of our solution if you simply compared D being higher than points C and B.

So I think this is an important part of the whole forecasting process. Now, maybe Jerry being from the National Coal Association and Ed being from TVA would probably know more about this than I would. Maybe after I'm done you could comment on whether you think this is an important omission or not.

Other models with coal preparation, the national coal model added it as an option technology, sandwiched between the mining and the transport steps. Our coal transport study, again, had a similar thing, but both of those were generalized network models, whereas NEMS is not. There are a lot of separate submodules.

If they choose to add this in later, how might they go about it?

Well, one option would be to have a coal preparation conversion model like their other conversion subcomponents, electricity, refineries and coal synthetics. I wouldn't necessarily recommend that because coal preparation is not really a conversion of one type of energy to another. It's just a beneficiation, but keeping it at the same kind of thing. It's still coal.

So I'm left with it fitting logically as part of the coal production submodel or between the coal production and coal distribution submodels.

One option would just be to make some exogenous assumptions and assume some historical rates of coal washing by coal type. You know, break it down by coal type and region. It's very safe to assume that coal preparation takes place at the mine now.

The trouble is that when the share is 45 percent for steam coal that you're just going to assume that it's 50 percent. It's not going to change? I don't have historical data to see whether that number is on its way up or on its way down.

And even so, past performance is no necessary indication of the future, which is why you're doing this whole modeling effort in the first place.

The disadvantage of this assumption is it's not flexible enough to do the modeling of the scrub-or-switch decisions. It's just an exogenous assumption. So now I go down to Option B, which would be to develop supply curves for the washed coals in addition to those for the raw coals.

I think coal preparation decisions are usually made at the same time as the decision to build the mine and would be part of those long-term contracts. So I think you could easily bundle it with the mine construction decision that's done in the CPS. You'd have to have some kind of additional control program. I don't think it would be any big deal to make sure that you don't double count any reserve blocks when you create two sets of supply curves.

The advantage would be the decision would be endogenous and that no new submodule is needed. The obvious disadvantage is it would double the number of supply curves, and that would double the number that are going into the CDS, which would more than double the length of time the CDS takes to solve, which is probably the conclusion you came to in not taking this direction, but I just don't think you can totally ignore it.

Option C is not something I'm really recommending. You could have a preparation submodule between CPS and CDS, but why separate it from the mining decisions if in real life preparation plants are rarely added on after a mine is built?

So now I move on to the coal distribution submodule. Again, I'll start with the purpose: to forecast minimum cost coal distribution and output, quantities of coal produced by region, mine type and coal type, the minemouth and delivered prices, the delivered Btu and sulfur contents, all of these by sector, region, and transport costs, traffic, volume and ton-miles by mode. The report says they're going to give outputs by mode, and I think that's pretty important to some of the consumers of your forecast.

At the same time, the CDS has to meet the NEMS requirements for a simple, fast and transparent model. These are all taken right out of the report. The non-NEMS requirement to provide additional detailed reports by state for some important states, and the need to test hypotheses about future transport rate changes and things like that.

And do all of this in the context of what's at the bottom there, the fact that coal distribution is governed by a lot of complicating factors, and I think the CDR does a very good job of listing and exploring all of those complicating factors. They didn't leave many stones unturned.

Deposits are widespread and heterogeneous. Demand is widespread with many possible routes. There are long-term contracts, old and new ones. There is supply diversification behavior, which is not necessarily cost minimizing. There's spot market buys. There's environmental regulation. There's railroad market power and captive shippers, etc.

So I come to this point. That's a pretty tall order to do all of that and to make it fast and transparent and simple. Is it even a possible task to be given? I sympathize with you.

Obviously you have to make some major simplifications to make it simple and fast. So what I'm going to talk about here is the tradeoff between these simplifications and their implications for speed, accuracy and flexibility, and what I mean by flexibility is how much flexibility is the model having to make decisions versus how much is being hard-wired, imposed as exogenous constraints, and how is accuracy being assessed.

All right. So now I'm going to quickly run through what I call are the major simplifications in the CDS.

The first three go together. They are origin-destination rates used instead of a network. There is no underlying network of nodes and arcs here. There is simply a matrix of Origin-Destination (OD) pairs with rates attached to them.

There's no endogenous generation of new paths or routes. There's no link-by-link cost. I'm going to address those three together.

In the coal modeling literature, this has been done in all possible combinations of ways. I've seen costs used instead of rates. I've seen links used instead of paths. I've seen each combination of each with the other, depending on what's the purpose.

For their purpose of predicting, production levels by region and by coal type, I think rates are the way to go as opposed to costs. It allows them to take into account a number of other things further down the list, such as carrier specific data or unit trains, scale of the shipment, etc.

And now going down to the fourth point, transport costs are not sensitive to annual volume or capacity utilization factors. I think that relates to the point of not using an underlying network. It also relates to the point further down that says no bottlenecks.

I think they make the point in the report that there are too many commodities to make any kind of internal decision in this model about building new rail capacity when there's so many other commodities that use the rail system. That's exactly true. We came to the same conclusion in China where actually the coal is close to 40-some percent of the rail traffic, and we still couldn't do it.

But jumping down a little bit, the assumption that there are no bottlenecks to be concerned with, I think that's maybe going a little bit too far. I've heard from some people in the Army Corps that they are worried about inland waterway lock capacity in the future. Now, if we can just assume that they're going to take care of that, then, you know, maybe we don't have to worry about it, but in short-term situations it could be a severe bottleneck.

Arbitrary contract imputation rules. Now, I got a fax with a memo about the changes to the modules, and I found that this had been dropped. I thought it was okay. Apparently it was dropped because there was no clear theoretical basis on which to impute contracts because minimum cost buying is not adequate. But their original point that long-term contracts do involve carriers remains a valid point. So I'm not sure which way you should go on that.

Updating transportation rates with some trend data, I thought that was reasonable. Of course, there are fluctuations with capacity, utilization, and number of barges, but, you know, it's a bit difficult to forecast that over 15 years.

Their heuristic algorithm is fine. They've been using it in the past with the CSTM model. No comment necessary.

Carrier specific data are not the default option. Now, in our modeling work of coal exports through ports, we found that was a very important factor. Different rail carriers have facilities at different ports and networks that go only to certain ports, and if you're trying to make predictions at the level of which port is going to have which kind of market share, it's important.

Is it important for your purpose? I would say that your use of transportation rates more or less alleviates you of the need to do this. I don't see any possible way for you to go down to the level of carrier specific data.

Your number of coal types, 32, I thought that was more than enough detail.

Number of demand sectors. Here, again, it seemed like you could almost aggregate some of them. For instance, export steam demand and industrial steam demand. If your regions were the same, you could aggregate them and just disaggregate them in a report, in a post-processor.

Now, getting to my main point, export demands assigned to five demand regions. I think the Atlantic region is way too aggregated. Sixteen supply regions, I think that's too aggregated, and 22 demand regions. I think all of these are too aggregated, which is agreeing with Jerry's point, even for the purposes that you state, for the questions that you say you're going to answer.

Now, of course, you're thinking that how aggregate your regions are depends on how you go about modeling certain things. In my experience, we used LP. They're using an equilibrium so that you don't have the knife's edge effect. Disaggregation is a little more important for LP models than equilibrium models.

If you have multiple coal types at each node, multiple steps for cost levels at each node, that will insure that you don't have big shifts, but in our China model we also had multiple coal types for each region. We had multiple steps for each coal type within each region. We still found that spatial disaggregation was the key issue in getting the results to be reasonable.

And for the export demands, I see that, for instance, the old CSTM module had a lot more detail, that was used, for instance, by the Army Corps' Mobile District to predict some coal flows. You could never do that with this new model.

Now, this is not a criticism that they didn't anticipate. They were very sensitive to this issue, and Scott and Robert and the other authors have tried to, I'd say, head it off at the pass. The report admits that as the number of origins and destinations decreases, accuracy and stability of the interregional tonnage weighted distances -- flows -- is going to diminish. That's true.

The next paragraph, the report states that detail about comparative route geography and link-specific economics has few applications to national energy policy analysis addressed by NEMS. I would agree at the level of comparative route geography and link-specific economics, but that conclusion does not transfer to the question of OD flows. They're not really the same thing.

It will have to be comparing routes. You can still be using a single OD rate, but the level of grouping is going to make a big difference to your predictions about coal production by regions.

Regional production levels, interregional flows, and mode totals are listed among the main forecasts to be provided. They are affected by the aggregation level.

I already made the next point, going down to second to the bottom. The CDS report cites the example of Ohio, how formerly they had divided Ohio into a northern region, which is near the lake; a middle region, which didn't have water transport access; and a southern region, which had access to the Ohio River.

In the new model, Ohio and Indiana demands are combined into a single unit with a single center. Now, I think if you think of a plant up near Cleveland one in Indiana, southern Indiana on the Ohio River, their production sources are going to vary greatly.

Now, when the CDR discusses this, they discuss it in the context of imperfect competition and non-cost minimizing patterns of supply and demand. It's true that utility buyers engage in non-cost minimizing behavior. They diversify their supplies to protect themselves. Is this pattern of a plant near Cleveland buying differently from a plant in southern Indiana an example of this non-cost minimizing behavior or supply diversification behavior? No. I think that's an example of delivered cost minimization.

Now, whether the plant in Cleveland diversifies with several sources, that's another issue, but its diversification of sources will be different than the Indiana plant. I know I'm kind of pounding this point in, but in my experience, it's crucial.

I've already made this top point about northern Ohio not being analogous to how importers spread their purchases.

I don't think you'll be able to make very valuable, reliable predictions about intermodal competition, about slurry pipelines with this level of aggregation, and this leads to the question of calibration.

Now, there's a section in each of the component design reports on uncertainty. To me uncertainty is not the same issue as calibration. Uncertainty is more sensitivity analysis. What's the range of this data, the actual number could possibly be, and how will that affect the results? And they do a very good job of discussing that kind of uncertainty analysis, which is not the same to me as the question of calibration which deals with the accuracy of the forecasting, not the sensitivity of the forecasting.

I didn't see any mention of how they're going to verify that the model is making sense and making good predictions, and it is a very problematic thing to do. I don't have any great answers to give you.

We keyed on that element of port flows for the Army Corps, but you know, what are going to be your calibration targets? They have to be aggregate types of things rather than very specific.

You do mention calibration. The word is mentioned several times. They talked about adjusting mine prices or imposing exogenous market share constraints as calibration parameters, but there's no discussion of what you're going to compare your model results to.

In my experience, in order to calibrate the model, you end up disaggregating nodes. You have a node that's combined. You end up splitting it into two, demand nodes and supply nodes, both, particularly with respect to water transportation, coal types, prices, carriers. All of these things vary geographically in very small areas. You've got to find the right level there.

So, in summary, I think that they're making incompatible demands on you. They want a very fast solution. They want accuracy, and I would think that all forecasters would want a reasonable amount of flexibility in their model.

Maybe you could do some experiments with a stand-alone coal distribution submodel and vary the number of nodes and do some kind of comparison. Just create some tradeoff graphs between the speed, some accuracy measures, and how much flexibility you've given it or had to not give it in order to get the calibration.

One way to calibrate is to fix a lot of shares, but then going to the future, how do you know those shares are going to hold?

So I think, in summary, you took into account all of the factors. You discussed them. The model conceptually is fine with me, but it would work a lot better with more origins and destinations, and some of the arguments made to counteract that don't seem to hold up, in my mind.

Now moving quickly, I don't have many comments on the Coal Synthetic Submodule. The purpose is to provide quantities of coal based synthetic fuels as inputs to the petroleum market and oil and gas modules. The overview is a three-step methodology decision to build the synfuels plant, a decision to continue construction, and then the decision to operate.

Now, in one of the other sessions I was in yesterday -- I think it was the electricity capacity planning -- one of the reviewers complained that they didn't have this kind of three-step decision-making in the electricity capacity module. So I really congratulate you for doing what they weren't able to do.

You cite that you use a profitability ratio to make the decision about building. FOSSIL2 uses an internal rate of return. There's no discussion of why you chose one over the other even though you mention it, and you don't list any limitations.

My only comment really on the synfuels submodule is that there is a limit placed on the number of synfuels plants per region, and this is a quote. "The user can set limits on the numbers of plants which could be built within each region in total and/or by capacity process type over the NEMS forecast horizon. Determine by considering siting factors, such as availability of water, environment, etc."

That's going to be a critical number. We had similar exogenous numbers in the China model, and it turned out to really make a big difference. It's really equivalent to the length of a coal supply curve. How many plants is how much you can build. So I think you need a methodology for this rather than "well, we can set a limit." It should be noted as a source of uncertainty, and you have a market penetration module which applies to the rate of introduction, but not to the total that can be introduced. So they're not the same things.

Now, the Coal Export Submodule, I didn't have a chance to review it, but I've heard a little bit about it just now, and I just want to make a couple comments.

There are two issues there about total demand for U.S. coal, of total export demand, and then how much of that demand will the U.S. capture. Now, on the second one, how much the U.S. will capture, you refer to it actually in the distribution submodule. There's some non-cost minimizing behavior, perhaps risk minimizing behavior going on.

I've always thought that actually it is probably cost minimizing behavior that foreign buyers engage in, but it's not delivered cost minimization. It's total cost where you also include some kinds of transaction cost. This concept of transaction cost is getting a lot of play in the literature now, and I'm wondering if there's some way it could be built in. I'm not sure how you'd even go about it.

That concludes my comments.

MR. SITZER: Okay. I have to thank the reviewers for going through these reports with all of the detail that they did. In fact, I heard some things that I didn't remember myself.

I do want to give you time for a couple of questions. First of all, let me just discuss some of the comments. I think the major comment I'm hearing concerns sufficient detail in the regional classification structure.

Mike is right. We are required to have a fast, transparent and operationally simple model, and one of the ways that we went about it was to reduce the detail.

If some of you have heard any of the other sessions, you probably know that one of the original blueprints for NEMS was the National Research Council's report on EIA's models and what it enhancements and improvements the Council felt needed to be made, and this was in light of the National Energy Strategy experience that the department went through a couple of years ago.

Coal was not given a high priority in the National Research Council report, and in fact, one of the things that was said was that detailed coal analysis should probably be done off-line and simply inserted exogenously into NEMS.

We at EIA feel it's very important that coal is a part of the integrated system. In order to keep it in the integrated system, we've had to make some compromises. I think that those will come out in the calibration, as you've said.

How will we calibrate? Basically we'll look at historical data. We'll look at our own

Annual Energy Outlook forecasts. We'll look at other model results, and we'll continue to discuss our modeling and forecasting activities in forums such as these. I think those are the primary ways that we'll go about calibration.

If we do find that this model is not detailed enough to support that kind of scrutiny, then we're going to have to give it a second look obviously.

Jerry, you talked about network models. Maybe the term "network" means different things to different people. We are keeping the CSTM heuristic, least cost path algorithm in the CDS. What we've eliminated, though, are the intermediate points.

In part, we eliminated them because we had difficulty in determining what rate structure was involved and in terms of determining actually how much capacity went over these different links between origin and destination pairs, and the difficulty of validating our results.

So we at least in version one of NEMS are going to try to model this as a straight origin-destination pair network. It's still a network model in the sense that it's finding the least cost way of distributing coal from the sources to the given demands. So in that sense it's a network model.

We will have the capability of putting in alternative rate structures and seeing what the impacts on distribution are. I think that's probably going to be an important policy tool for us, but we have eliminated the intermediate link structure that's in the CSTM.

Coal synthetics, does need to get up and running. I agree with you. It's a question of coding, testing, implementing, and documenting, and those are the steps that are required and the steps that take up resources.

It will be done, but I don't think we'll be able to get it in by April 30th.

Imports were not well mentioned. Basically we haven't looked at imports in a modeling sense. We have looked at imports in more of a trend against recent history. The imports that are in the model now were essentially developed a few years ago. We will go with those for the moment.

I think the forecast is 11 million short tons out by the year 2010, and that is simply decremented from current production requirements of domestic coal producers. We will need to take a second look at imports particularly in light of the Clean Air Act Amendments.

Ed talked about contracts. We did, as Mike said, eliminate an explicit estimator for contracts in the revised version of the CDR. Nevertheless, this is not going backwards so much as it's not improving the current model.

The current model has current contracts in it. As they expire, they are not replaced specifically in the model. We've had an awful lot of discussion about this and the impacts on prices of contract versus spot purchases. Even in our original proposal the main use of contracts would be to stipulate particular sources as opposed to particular prices.

It's an issue to debate. I think we'll continue to have it, and as we learn more about contracts and how they might go into the model, we'll be making modifications.

Your comments on the demonstrated reserve base, of course, I've known about for some time. EIA is now in a mode of improving the DRB mainly by going to some of the state geological surveys and trying to determine what they think their demonstrated reserves might be and helping us to update our own demonstrated reserve base in light of their activities.

In fact, I think we've updated Wyoming and Ohio now, and we may have other states for whom we're going to be providing some resources for them to help us.

I agree the DRB is probably the key issue in the RAMC model, and different people's estimates of what the DRB are would certainly impact on coal prices. We at least had the capability of making those different estimates, and we need to keep working with the data people to see that the estimates are defensible.

Coal preparation. I was so impressed with your arguments that we're going to put coal preparation in the model. I'm not sure how we're going to do it.

I think that part of it is covered now in that the historical data that we have includes standard coal preparation done after mining. In other words, it's not completely raw coal, but rather from the time the coal departs from the production facility some preparation has been done, and that's included in the survey data which we use to calibrate our model.

So it's not completely left out, but your switch or prepare decision is not well represented in the model now. We want to do it, and I think the important thing to do is to collect some data on the cost of preparation and to fit it between the production and the distribution decisions, and we do have resources to do that. I don't know if we'll make it by April 30th, but we will make it this year.

There are others, but I think I want to give you all a chance to ask questions, and if we have any, I'll take them now. Yes, sir.

MR. WATSON: I'm Bill Watson from the U.S. Geological Survey, and I'd just like to add a little bit to what Ed Julian said about the demonstrated reserve base. He mentioned Hill & Associates and also the work that's been done on EPRI on coal reserves in Appalachia.

For about the last three or four years we've had a similar program underway at the U.S. Geological Survey, working with principally Kentucky and West Virginia, and we're finding results that are very similar to the ones reported here by Ed.

That is, if you look very carefully at the mining activity that has taken place there historically and the kinds of restrictions that are in place there now on access to coal, and you do some careful data gathering on coal drill hole samples, very detailed work, it's very striking the small amount of coal relative to the numbers that are out there that appears to be left available for future mining.

We have taken some of that reserve data and put it into our own model of the coal market, which is also a linear programming, cost minimizing model. However, it's solved dynamically over time so that it endogenously generates rents, and we also see the kind of rents that Ed was talking about here today cropping up in prices.

And I might add that you don't really have to have a monopolist there. These rents will occur also in competitive-like market structures, and if these reserve numbers are on target, in line with reality, there are some pretty high prices cropping up on some of that low-sulfur coal in Appalachia.

So I would encourage EIA to perhaps rethink its position with regard to the DRB. Do the best job you possibly can at this point to update those numbers. Go to the people who have been doing some work on them, and see if you can't make some improvements there.

MR. SITZER: Comments anybody? Jerry?

MR. KARAGANIS: Well, one of the things that in looking at the model that I was thinking about was if I have the supply curve straight, you basically allocate 30-year requirements to each mine you open, but you don't have anything like a logistics curve to mine out an area. In other words, you can keep producing it until the last drop, and you get done as opposed to saying people would take actions before, if and when production started to decline.

My suspicion is that you'd start seeing severance taxes and a lot of other things that would place the premium on those coals. So they just don't get mined out quickly. They'd be stretched out. That's my opinion on that.

I just wanted to add on your prep. plant stuff, and it goes back to a comment I wanted to make. You calibrate your supply curves to an FOB mine price when you do that, and when you do that, you're basically taking the mining characteristics and then taking the value added that goes into the coal, and when you look at your delivered costs and subtract off FOB mine price to figure out transportation, you are capturing a lot of the prepping. A tremendous amount of the prepping is being picked up. That's why I didn't say anything.

But in that light, it bothers me: if I had a supplier like Pennsylvania where I know a lot of de-ashing is taking place, and I'm selling all Pennsylvania coal, which has an average prepping in it for out-of-state coals; that if some area bought into it, it may, in fact, be subsidizing some other area.

So the simple fact of a single price for a type of coal out of an area because you've got sulfur and you've got Btus, you don't have ash; you don't have a lot of stuff. That is troublesome to me. In the end you could put a little matrix, I guess, on an area and try to account for all of these things like an adder for additional prepping or, for example, if you're coming out of the West, how are you going to handle de-moisturing of coal, which could be a very big thing?

There probably has to be some sort of mechanism on top of that price for doing quality adjustments.

MR. SITZER: Richard.

MR. NEWCOMBE: Thank you.

Richard Newcombe, EIA.

I just wanted to say that currently we are capturing a great deal of the coal preparation activity because the CDS as it's now running is calibrated on the Form 423 values for Btu and sulfur as received by the utilities, and the FOB mine prices include the cost of preparation where relevant.

We're kind of in a hard place to talk about what we're going to do about coal preparation. We're meeting with our contractor tomorrow to scope it out and begin talking about it.

I recognize that there is enormous variability in coal preparation. I know that you can take two coals from different regions that have the same total sulfur content. For instance, if you take the Illinois Number 6 coal, you can throw away 40 percent of the coal and get a 20-percent sulfur reduction. You can take the Upper Kittaning Seam in Pennsylvania with the same sulfur content and throw away 20 percent of the coal and get a 40-percent sulfur reduction.

So we're aware of those kinds of variabilities. We know that we will have to do some kind of simplification to the regional level to get something at an appropriate scope for the model, but we're also aware of the dangers of throwing away variability.

MR. KARAGANIS: Can I just add something to that?

If you've got limited dollars to invest, my understanding is that you're going to get into coal blending, and if you've got a choice between prepping and coal blending, I think coal blending, given the Clean Air Act and given what Ed is talking about, certain types of coals getting mined out, the coal blending is, I think, by far the more important.

MR. NEWCOMBE: You may be right.

One issue that obviously comes to mind is, given the outlook for exports, we have to consider that the market for prepared coals may be very different internationally than it is domestically, and this will certainly affect the way we model preparation in the Appalachian fields, at the very least.

MR. SITZER: We probably have time for one more question formally. Yes, sir.

MR. BRODERICK: Yes. I'm John Broderick with the Bureau of Land Management.

As some people here know, I've dealt a lot with DOE models, especially the coal models.

One of the problems I've found, and you know, I deal a lot in the western regions, was a mismatch between the transportation network and the way the coal regions were defined. I see that the further aggregation in the West is going to exacerbate that problem; the way it stands now may be fine for looking at national level issues, but if you want to get into regional coal issues, then this is really just a screening model, and you're going to have to go into something more disaggregated.

Specifically, if you look into the other West, how do you take into account the differences between where, say, in the Green River in your western regions where there's a lot of mining activity that has close access to the railroad versus the Four Corners area where virtually none of it has access to railroads, and that makes a big difference.

We had done a study--I can't remember how many years ago--on coal transportation that raised a little controversy. We were specifically looking at the impacts of having two-railroad access into Powder River. Many people, forecasters, were underestimating the impact that would have on the Powder River production, because it knocked the rates way down.

The transportation factor really is a major factor in the coal market, and I think that the level of aggregation misses a lot of that.

MR. SITZER: Okay. Do you want a rejoinder on that?

Okay. One more comment, one last comment.

MR. NEWCOMBE: I wouldn't deny the importance of disaggregation in the coal model at all, but perhaps the Coal Market Module is not quite as aggregated as it may look. We have currently 23 demand regions and 16 supply regions and up to seven transportation modes. That means that, in effect, there are 2,500 coal transportation routes in the model.

Well, maybe we're only going to be using half of them because we don't have seven modes you'll say from Wyoming to Illinois, but in effect, each one of those modes can be used to model a specific carrier.

When we made the supply regions, I tried to look at it as getting two Class I railroads per supply region because there are enough modes so that if we prepare cost estimates or price estimates exogenously, we can insert them and treat them as modes in the model.

The overwhelming design feature here is that we must have a flexible model. We must have something that can deal with fairly detailed studies and at the same time can run very quickly and is very simple and easy to maintain, and for non-coal professionals to use if it's ultimately installed on PCs and made accessible to outside users.

So we have to do both, and as Michael Kuby said, it's a tall order, but it means that a lot of the detailed concerns which people are rightly expressing here can be dealt with through exogenous work that is then inserted into spaces left available in the model and then used specifically for that purpose.

MR. SITZER: Okay. With that, I think we'd better close. We're a little over.

And I do appreciate your coming to this session and to the NEMS conference, and I hope we'll see you again soon.

THE NEMS CONFERENCE

ELECTRICITY FINANCE AND PRICING PANEL

February 2, 1993 - 10:45 am

PANELISTS:

Mark Gielecki, Moderator
Arthur S. Holland, Presenter
Leonard Hyman, Reviewer
John Kelly, Reviewer
Terri Carlock, Reviewer

AUDIENCE PARTICIPANTS:

Paul Holtberg
Scott Rogers
Jack Butler
Virginia Sulzberger
Joseph M. Dukert

EIA

PROCEEDINGS

MR. GIELECKI: Good morning. Welcome to the panel on electricity finance and pricing. The Electricity Finance and Pricing Submodule is a component of the Electricity Market Module, and of course, it's all part of the NEMS system.

Presenting the description of the Electricity Finance and Pricing Submodule this morning will be Art Holland. Our reviewers today are Leonard Hyman, John Kelly, and Terri Carlock.

My name is Mark Gielecki, and I'm the Team Leader of the Nuclear and Utility Finance Team within the Nuclear and Electricity Analysis Branch at EIA. I've been working around electricity issues for 15 or so years, and prior to that, I was in systems analysis at the NASA Goddard Space Flight Center.

Our presenter today, Art Holland, is an Operations Research Analyst on our team and in our Nuclear Electricity and Analysis Branch at EIA. He has previously worked in the predecessor organization, the Electric Power Division at EIA. And before coming to DOE, he spent years working in the financial services industry.

Art has an MBA with concentrations in Finance and Management Science from Virginia Tech, and he has pretty much developed the Component Design Report which you are about to hear.

Art?

MR. HOLLAND: Thank you, Mark.

Good morning. Thank you for attending this session on the Electricity Finance and Pricing Submodule, and thank you for the wealth of feedback that we've received so far on the NEMS.

The Electricity Finance and Pricing Submodule is the last sub-module in the Electricity Market Module. Jeff Jones has reviewed this slide more than a few times, so in the interest of brevity, I'd like to simply remind you of the submodules within the Electricity Market Module. They are the Electricity Trade and Transmission Submodule, Load and Demand Side Management Submodule, the Non-Utility Generation Supply Submodule, the Electricity Capacity Planning Submodule, and the Electricity Fuel Dispatch Submodule.

The purpose for developing the EFP, the Electricity Finance and Pricing Submodule, was to produce a flexible tool for the pricing and accounting functions of the Electricity Market Module of the NEMS. Operating at the level of the 13 North American Electric Reliability Council supply regions provides for analysis based on the actual operational characteristics of the national grid. This allows us to incorporate actual load characteristics, for example, in our cost allocation algorithms.

Alternate pricing algorithms give us the flexibility to capture emerging pricing methodologies in the electric power industry and to ensure consistency in the underlying

Electricity Finance and Pricing
in the
National Energy Modeling System

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Arthur S. Holland
Energy Information Administration

EIA

February 2, 1993

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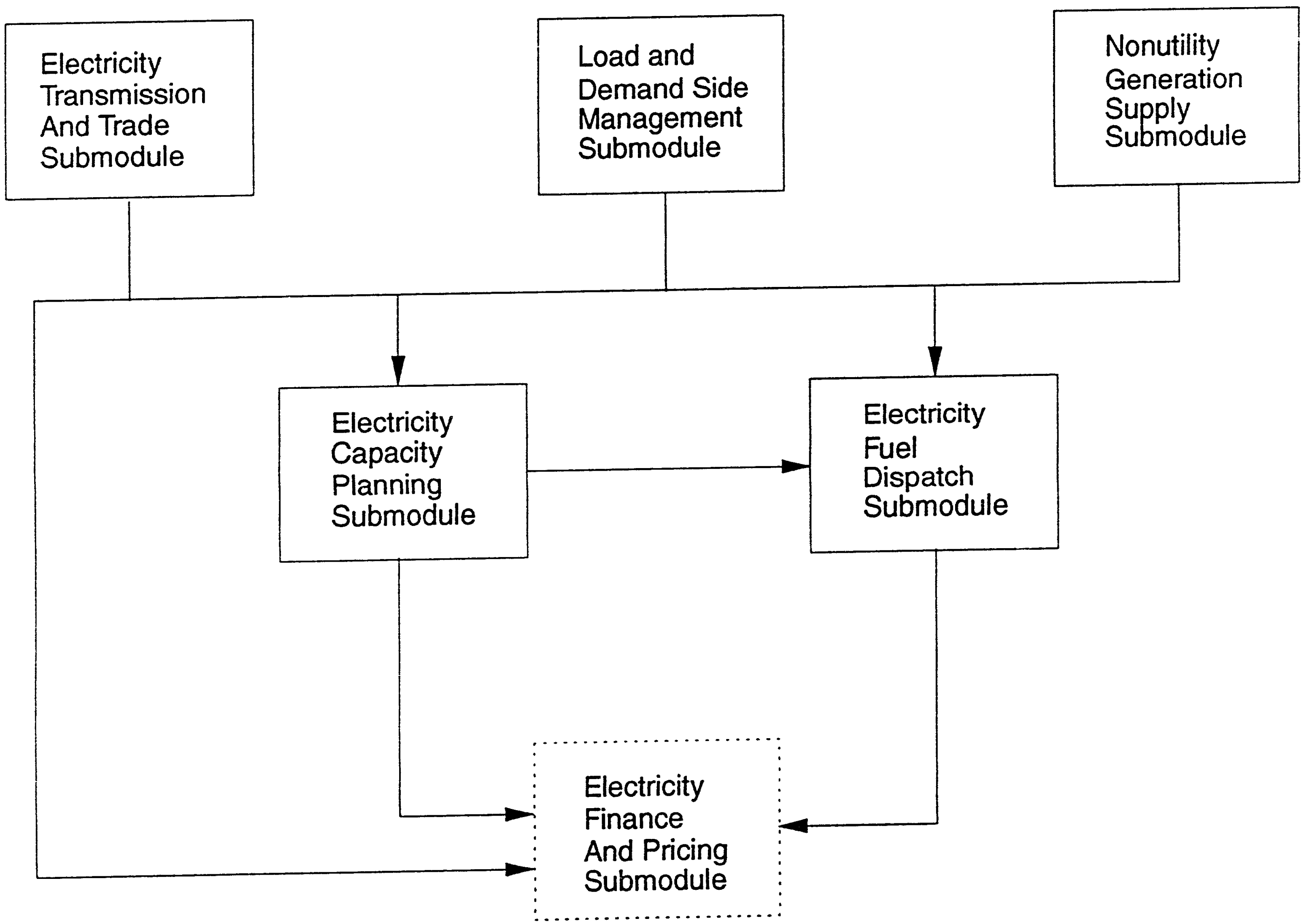
Information Flow Within the Electricity Market Module



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Statement of Purpose

- Represent the Accounting and Pricing of Electricity
- Operate At 13 Electricity Supply Regions Based On NERC Regions and Subregions
- Incorporate An Alternative Pricing Methodology
- Account Separately For The Costs Associated With The Generation, Transmission, and Distribution Of Electricity
- Include Enhanced Representation Of Capital Investments

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economic assumptions common to various submodules within the EMM, the Electricity Market Module. I'll be discussing these in more detail. The separation of generation, transmission, and distribution in both the accounting and the pricing functions of the model provide similar flexibility in using emerging pricing methodologies and varying regulatory treatment for each of these stages of production.

I'd like to discuss this final point, the enhanced representation of capital investments on the next slide. These are the issues that we believe have significant accounting, tax, pricing and political importance to policymakers.

Demand Side Management: Previously, the Energy Information Administration's finance model, which was called the National Utility Financial Statements Model, did not explicitly address DSM expenditures. They were treated just like any other expense. The EFP, the Electricity Finance and Pricing Submodule, can be used to analyze the pricing and accounting impacts of demand side management programs. The Load and Demand Side Management Submodule sends the EFP the costs of DSM programs and how to allocate those costs among the four customer classes in the Electricity Market Module.

Nuclear Plant Decommissioning Costs: The Electricity Finance and Pricing Submodule has explicit balance sheet and income statement items for this decommissioning liability. Life extension was previously done off-line. The EFP provides, again, for explicit accounting and tax treatment of post-operational capital expenditures which previously were treated like any other capitalized outlay.

The Compliance with Clean Air Act Amendments of 1990 and Emission Allowance Trading: The EFP will explicitly account for the costs of compliance and the costs and revenues of allowance trading.

As for the pricing of electricity, the EFP produces a unique price for each stage of production. That's generation, transmission, and distribution. It does this by ownership category, that's utilities versus non-utilities, for the generation stage of production.

The steps used in this process are shown here. The first step is to determine functionalized cost. By functionalized, we mean by stage of production: generation, transmission, and distribution.

The second step is to classify all costs. We classify costs into capital-related, fixed O&M, variable O&M, and fuel-related. Then each of these functionalized, classified costs are allocated to the customer classes using a unique method for each of these itemized, classified, functionalized costs. The method that we use for each is the method that best conforms with the economic and regulatory assumptions that are underlying that particular cost. At that point, it's a very simple matter to calculate electricity prices because you have your costs allocated to each customer class and you know what the kilowatthours of sales are to each class.

I'd like to go into a little more detail about each of these steps. Functionalized costs are determined, for the most part, in other submodules. This slide shows where these major cost items come from. As you can see, other than the costs associated with distribution, these costs

Enhanced Representation Of Capital Investments

- Demand Side Management
- Nuclear Plant Decommissioning Costs
- Power Plant Life Extension Costs
- Post Operational Capital Costs
- Financial Treatment Of Compliance With Clean Air Act Amendments Of 1990

Electricity Pricing

Step 1: Determine Functionalized Costs

Step 2: Classify All Costs

Step 3: Allocate All Costs To Customer Classes

Step 4: Calculate Prices For Each Customer Class

Electricity Pricing
Step 1: Determine Functionalized Costs

Generation	Electricity Capacity Planning Electricity Fuel Dispatch
Transmission	Electricity Transmission and Trade
Distribution	Load and Demand Side Management Electricity Finance and Pricing

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come from the other submodules within the Electricity Market Module. The EFP does determine some of the costs that are associated with the distribution stage of production.

These are the two options for pricing that the EFP has in its initial form. Now, these two pricing algorithms have to do with the determination of cost as well as cost recovery. And that's why I'm discussing them here in step one, determining functionalized cost.

Option one, traditional average cost-based pricing. These are the characteristics of this method and these characteristics are at the root of what is known as rate of return, or cost of service rate-making. Retail rates for most electric utilities are set this way. Alternative regulatory frameworks are, for the most part, departures from this method -- departures to varying degrees in order to provide for management incentives. This method is characterized by imbedded cost and declining fixed cost recovery.

The levelized cost-based pricing algorithm will be used to simulate wholesale prices that utilities will see as a result of purchased power contracts. The costs of the plant that actually generates the energy are used to calculate the price. And as I mentioned earlier, the recovery of the fixed costs of production decline over time in traditional average cost-based pricing.

In the levelized cost-based pricing algorithm, these fixed costs are levelized, that is annuitized. What that means is that the present value of these fixed costs is equal to the present value of the recovery of the fixed costs in the traditional method. But since these revenues are levelized and revenues in the traditional method are declining, that means that the cash flows from year-to-year will be different, and consequently, the prices will be different from year-to-year for the two methods. The fundamental difference between the two pricing methods, the two pricing algorithms, is the treatment of the recovery of fixed costs.

These are the pricing algorithms shown in matrix format for the various sources of energy and the stages of production. Except let me point out to you cogeneration. These prices are not produced in the Electricity Finance and Pricing Submodule. These are priced in the Industrial Demand and Refinery Models.

Again, the point that I want to emphasize here is not the relative merit of one pricing algorithm versus another, but that we have built into this submodule the flexibility to choose among various pricing algorithms. It is most likely that the average cost-based pricing algorithm will be used for utility generation, all transmission, and distribution, and the levelized cost-based pricing will be used to simulate the cost recovery implicit in wholesale purchase power contracts. But again, the emphasis is on the flexibility to plug in new algorithms or change these as we feel the need has arisen.

Step two. Once we've obtained the functionalized costs, they are classified into these categories. These are capital-related, fixed O&M, variable O&M, and in the case of generation functionalized costs, fuel-related. And here, I can point out that for each of these cells -- that being a cell, that being another, and this being one, and this being another -- we can use a different allocation algorithm to allocate these costs to the various customer classes.

After all the costs are functionalized and classified, they are allocated to the four

Alternative Pricing Methodologies For New Generating Resources

- Traditional Average Cost Based Pricing

- Levelized Cost Based Pricing

Option 1: Traditional Average Cost Based Pricing

- The Costs Of All Generating Units Are Included In The Calculation Of Production Costs

- Recovery Of Fixed Costs (Depreciation and Return On Investment) Declines Over The Life Of The Asset

- Currently Used For Pricing Electricity Generated By Utilities

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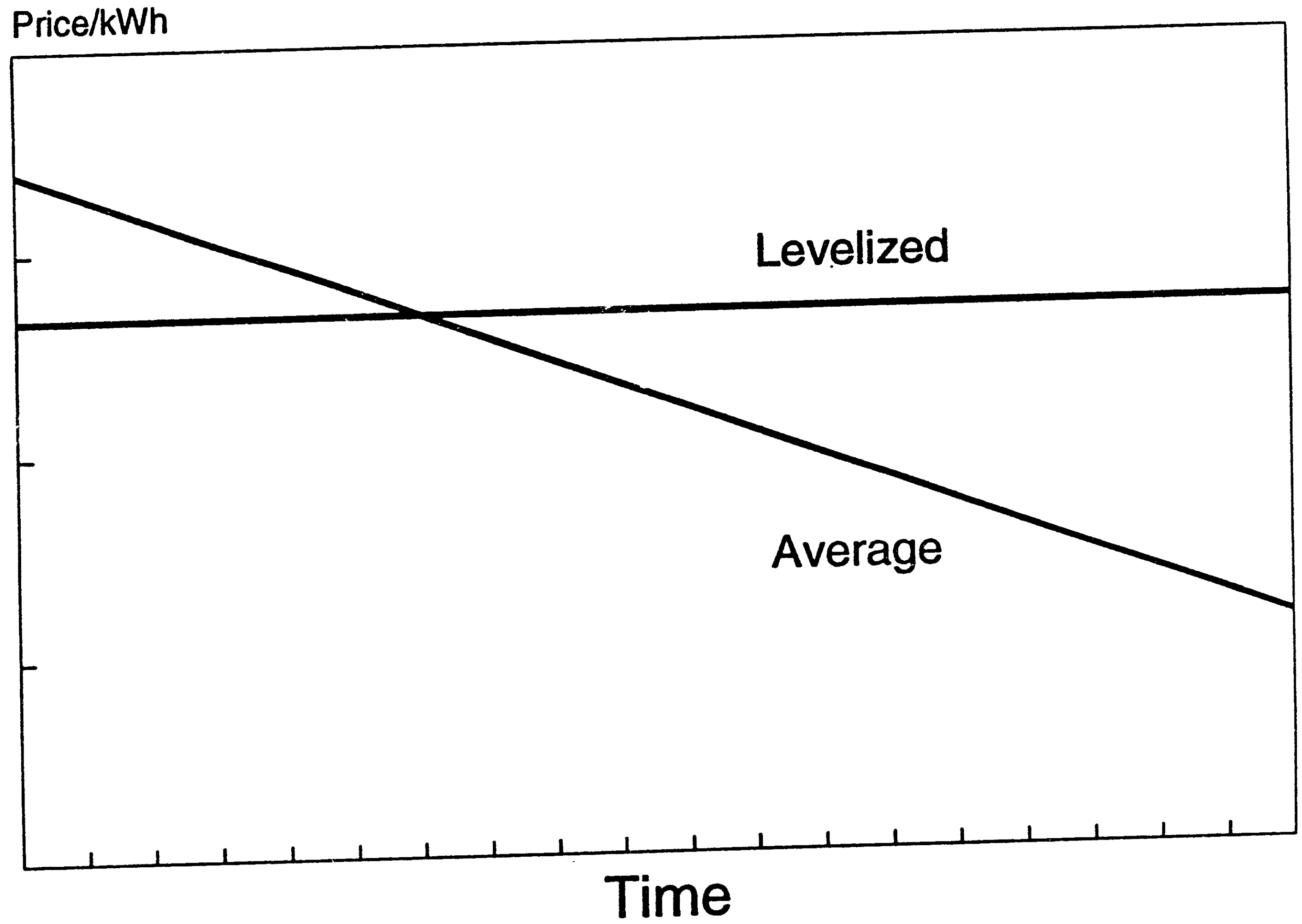
Option 2: Levelized Cost Based Pricing

- Marginal (Incremental) Costs Of The Generating Asset Are Included In The Calculation Of Production Costs

- Recovery Of Fixed Costs (Depreciation and Return On Investment) Are Constant Over The Life Of The Asset

- Used To Represent A Pricing System Where All Producers Are Paid The Breakeven Price Based On Their Own Costs

Average Vs. Levelized Pricing
Capital Related Costs



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Pricing Algorithm Choices In The Electricity Finance And Pricing Submodule

Stage / Source Of Energy	Generation	Transmission	Distribution
Utility	Average Levelized	Average Levelized	
NUGS IPP	Average Levelized	Average Levelized	Average
NUGS Cogen.	Avoided	Not Applicable	

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Electricity Pricing
Step 2: Classify All Costs

1009

Generation

Capital Related
Fixed O&M
Variable O&M
Fuel

Transmission

Capital Related
Fixed O&M
Variable O&M

Distribution

Capital Related
Fixed O&M
Variable O&M

Electricity Pricing
Step 3: Allocate All Costs To Customer Classes

Generation

Capital Related | Fixed O&M | Variable O&M | Fuel

Various Cost Allocation Methods
Unique to Each Classified Cost

Residential | Industrial | Commercial | Transportation

1010

customer classes. This slide shows generation costs as an example. Each functionalized classified cost category can be allocated using a different allocation technique as I mentioned. And as I said, this can be done for each functionalized and each classified sub-categorization.

These are the seven cost allocation options that are available in the Electricity Finance and Pricing Submodule. Now, I'm not going to go into the details of all of these. What I would like to go into are some of the details of the ones that we envision as being the default allocation methods.

In the sales method, which is used for variable O&M, down here, all the way across for each of the three stages of production, we envision using the sales method to allocate those costs. That's simply a proportion of sales to each of the customer classes which will be used to allocate these costs.

The non-coincident peak method -- which is here, here, here, and here in conjunction with one of the other ones which I'll be discussing in a minute --these are for the capital related and fixed O&M transmission and distribution related costs. In this method, the non-coincident customer class peaks are summed. Costs are allocated on the basis of the proportion of each customer class's non-coincident peak load to the sum of these non-coincident peak loads.

The average and excess demand method -- again, this is shown under generation for the capital-related, fixed O&M, and will be used in conjunction with the transmission capital-related and fixed O&M. In this method, average demand refers to sales. Excess demand refers to the coincident peak, not to be confused with the non-coincident peak I was just discussing. This cost allocation method recognizes that capital additions are not made solely for peak demands. Sometimes capital additions are needed for fuel cost savings and other sales oriented reasons.

In this method, costs are first divided into those that will be allocated on the basis of average demand, which is sales, and those that will be allocated on the basis of excess or coincident peak load demand. Those costs to be allocated on the basis of average demand are allocated first. Then the remaining costs are allocated on the basis of each customer class's contribution to the system peak.

The marginal fuel method is the last cost allocation method that will be used for the generation fuel-related costs. Transmission and distribution don't have fuel related costs, so that will be the only one it will be used for. I should point out before I go into how this works that we're not allocating marginal fuel costs. We're just using marginal fuel costs to determine the proportions of average fuel cost that we're allocating to the various customer classes.

In this method, each customer class' proportion of total load is determined in each of the load periods that are going to be used by the fuel dispatch sub-module. These proportions of total customer load are multiplied by the marginal cost of fuel in each period. And then this product is used as the proportion of fuel cost to be allocated to each customer.

Once costs have been allocated to each of the four customer classes, the sum of the allocated cost is simply divided by the sales to each customer class to determine the cost per kilowatthour of providing service to each class. Now, this quotient is the average revenue for

Cost Allocation Options For Each Classified Cost

- Sales
- Coincident Peak Method
- Probability of Contribution to Peak
- Non-Coincident Peak
- Average and Excess Demand
- Embedded Fuel
- Marginal Fuel

1012

Default Cost Allocation Methods

Stage / Cost Classification	Generation	Transmission	Distribution
Capital Related	Average and Excess Demand	Non-Coincident Peak, Average and Excess Demand	Non-Coincident Peak
Fixed O&M	Average and Excess Demand	Non-Coincident Peak, Average and Excess Demand	Non-Coincident Peak
Variable O&M	Sales	Sales	Sales
Fuel	Marginal Fuel	Not Applicable	Not Applicable

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Electricity Pricing
Step 4: Calculate Prices (Average Revenues) For Each Customer Class

Price per kilowatthour =

1014

$$\frac{\text{The Sum of All Costs Allocated to the Customer Class}}{\text{Kilowatthour Sales To the Customer Class}}$$

forecasted price.

Again, let me thank you for the opportunity to speak with you this morning. I look forward to your questions and comments and to hearing the comments of the reviewers as well.

MR. GIELECKI: Thank you, Art.

I just realized he's covered a lot of the ground very quickly. In any event, we have our reviewers here who have seen the written material before and are now ready to give us their comments.

Our first reviewer today will be Leonard Hyman. Leonard is the first vice-president and head of the utility research group at Merrill Lynch. And he maintains research coverage of domestic and foreign utilities, has consulted with several Canadian electric utilities, worked on privatization of British electric utilities, and has analyzed telecommunications issues for numerous countries.

He has held many very substantial positions in the past. He is a member of the United States Energy Association Institute of Chartered Financial Analysts, New York Society of Security Analysts, American Association for the Advancement of Science. And he's listed in the Who's Who in Finance and Industry.

Leonard, please.

MR. HYMAN: And I went to Stuyvesant High School.

I am approaching this with a certain amount of trepidation. I wasn't the star of the mathematical economics course in graduate school. I also remember a departmental seminar during which the econometrics professor filled the blackboard with equations to explain the economy. At that point another professor got up and said, "I can do this as well with five equations, and as far as direction goes, I can do better by fitting a ruler to the last few points."

Also, we have Leontieff's famous complaint that economists nowadays don't look at data. And I can't help but think about Alfred North Whitehead's phrase, (applied to something else), "the fallacy of misplaced concreteness."

Having put in all these qualifiers, I will say that am impressed by the thoroughness and diligence of the Energy Information Administration's effort and I'm happy to say that, because I have been using the reports for years and I'm glad there's something behind the numbers.

What worries me is the possibility that the EIA has perfected a model for a system that won't exist 10 years from now. The model is based on traditional regulatory procedures, and the accompanying financial ratios, concepts of recovery of costs, and industrial structure. Yet, the debates today are about competitive pricing, recovery of stranded assets, retail wheeling (which would destroy the integrated monopoly), and what impact procedures such as demand side management, integrated resource planning, and incorporation of externalities into decision making would have on utilities in a partially competitive market. In some ways, we have seen the introduction of competition simultaneously with more regulation, which makes the situation more unpredictable.

I will touch on a few aspects of the model, following the order of the text (Component Design Report, Electricity Finance and Pricing Submodule, Draft 4/10/92).

First of all, the model "has been designed to simulate the traditional original-cost or rate-of-return regulatory method." But that method is going to have diminishing relevance for several reasons. There is the lessening ability to collect regulatory assets from customers due to competition that makes price increases impossible or due to the just plain unwillingness of regulators to face the music. In other words, there are assets on the books now that are incorporated in the model that are or will be worthless.

Secondly, we have another question which was alluded to, namely the development of revenue and profit streams that don't depend on ratebase. One example is a reward for demand side management. Another example, which is not here yet, but I think will be here soon, is a margin on purchased power; I think that's going to have some impact on how utilities do business. There's also incentive regulation, again, alluded to, which rewards better operating procedures and more effective deployment of capital.

But finally, we've got to deal with the whole issue of the possible disintegration of the utilities in a way that may put a greater percentage of the assets outside explicit rate of return regulation. At that point, it's not going to do to simply say, "We've got the parts separated and we're looking at the separate costs." In many instances, the price is not going to be set by what the accountants claim is the cost. The price will be set by market conditions.

Now, this model was put together by some very smart people, so it anticipates a number of those objections by noting that the industry could disintegrate, in which case, independent power plants would supply an increasing portion of the industry's needs. This then, brings another sub-set of questions about the rise of non-utility generation, in the sense that it creates uncertainties and hidden costs, some of which may not be properly considered in the model.

Item number one, which is getting a lot of attention now. Bond rating agencies have begun to consider purchase power contracts as the equivalent of debt. This either raises capital costs or it causes the utilities to change the capitalizations they're going to use to protect the bond ratings.

Secondly, paying the utilities an adequate margin on purchased power could change attitudes of the utilities towards purchasing power. And it might very well open the flood gates to purchased power and may put the utilities out of the new generation business. That's assuming that the National Energy Policy Act (Energy Policy Act of 1992) didn't do that already.

Another item. Any serious attack on obligation to serve, coupled with freeing (or forcing) the large customer to find its own power sources could affect the ability of the independent producer to function as before, because of the financial uncertainty created by lack of long term purchase contracts signed by utilities.

Also, competition from independents is forcing utilities to tackle their own construction projects in a more cost-effective manner, so utilities may beat their capital expenditure estimates.

Now, the model depends on ratebase and recovery of expenses. The books of account though, are going to give us less and less guidance, and here are the reasons.

The books do not reflect potential asset write-downs from or the distribution of profits on sale of assets or probability of collecting non-tangible assets, so-called regulatory assets. A lot of companies have these non-tangible assets now. They're, in effect, money owed to them by customers.

A number of large facilities, usually nuclear, can't sell electricity at a competitive price and still earn a full return on assets. Unless competition could be put off until these facilities are more depreciated their owners may have to write them down to reflect market value. And, lest one consider this too far off, take a look at what's happening in New Mexico right now. The same type of analysis applies to so-called "stranded plant" that might be created by retail wheeling, although the energy bill provides some defense. What I'm saying is that you can't depend on earning a return on assets that are going to drop off the books.

We mentioned nuclear de-commissioning and spent fuel expenses. If they're underestimated, they may very well be uncollectible in the future when competitive price (and not an allowed return) drives the revenue calculation.

Other regulatory assets. These are usually in the form of revenues deferred to a future date. They're going to prove to be worth less and less because the regulators are either willing to push off their recovery, as was the case in Washington State recently, or because the utility deferring the revenue -- which is really the price increase -- may not be able to raise prices enough to recover the assets in the future due to the existence of competition. This is taking place right now in Ohio. You may want an example. Keep in mind that the regulators saw to it that the losses incurred upon cancellation of take-or-pay contracts -- which had been entered into for the benefit of consumers -- could not be passed on in their entirety to consumers. In other words, the utilities had to eat part of the cost. What I'm saying is that you may have a repetition. The same regulators oversee the electric business.

On the other hand, there's also the possibility that utilities might be able to sell some assets above book value. Will the benefit of that accrue to the utility or to it's customers? And again, I don't know.

Of course, because this is "a deterministic accounting model," there is no uncertainty within the model. There is uncertainty about the model inputs and assumptions. The draft focuses on the uncertainty of inputs in the areas of environment and interest rates. I would suggest, certainly in the area of environmental uncertainties, that they may be bigger than envisioned. Just consider the carbon tax. What would its impact be on the competitiveness of gas versus co-generated electricity, on the price and demand for electricity, and maybe even as a further incentive to self-generation under the new Energy Act (Energy Policy Act of 1992)?

Consider whether new environmental or safety rulings may give utilities the necessary excuse to close down nuclear stations rather than put new steam generators into them. Also, consider whether in this age of creative bankruptcy, hard-pressed utilities -- facing slow demand, over-capacity, new forms of supply, and competitors who can put up more economical facilities than the utility operates -- will reconsider their financial policies, the sanctity of the dividend, and what the balance sheet will look like if assets are not only stranded, but maybe even marooned.

Finally, I think the model is probably least likely to succeed on a regional basis, especially where high cost utilities face real competition. That's where you're going to have the most write-downs and the most problems, trying to come up with a price of electricity that has something to do with an accounting cost. The draft report, though, notes that "emerging issues . . . may need to be addressed." I think that's certainly true. Otherwise, the users of this model in the 1990s are going to have a perfect model for the 1980s.

I really wonder, given what's happening in the electric business, if it might not be better to put aside the model building for a year or two until the dust settles. Thank you.

MR. GIELECKI: Thank you very much, Leonard.

Our next reviewer is John Kelly. John is Director of Economics and Research for the American Public Power Association and he's been with them since 1982. Prior to that, he was an economist at a number of agencies, including Congressional Research Service, U.S. Bureau of Labor Statistics, Library of Congress, and the Executive Office of the President. I don't believe he went to Stuyvesant, but maybe he went to Walt Whitman. He's from the Washington, D.C. area.

John?

MR. KELLY: Good morning everybody. Whoever chose us to be panelists, they probably couldn't have done a better job, because my comments will contrast with what Leonard had to say in terms of the structure of the electric utility industry in the future.

I'd like to begin with just a couple of general comments. First, about the model. It is pretty daunting to go through it. And I have to admit that, like Leonard -- I guess this is one of the things I agree with him on -- I'm a little bit skeptical of the results that it may produce, from a couple of areas. One is the problem with data that goes into the model: the whole problem of matching economic concepts with the actual data you have to work with, whether it be rate of return data, cost data, allocating overhead costs. And I get some of the skepticism from about ten years of working with my association's rates and load research committee. Looking at the problems and just determining rates and load forecast for an individual utility can be very arbitrary and there are a lot of data problems.

You know, however, having said that, I think it's a worthwhile effort and my advice would be to go slow, be careful, and make sure that the data match the economic concepts that you're trying to build into the model. One thing, I think, that is very good, something that will address that problem is making the model flexible, and I applaud that effort.

I spoke briefly with Art about one kind of data problem: the accounting treatment of AFUDC, allowance for funds used during construction. For example, during the 1980s, financial analysts' government reports would routinely miscalculate this very basic piece of information. Cries would go up about the earnings of utilities that "most of them are paper earnings." Well, there was a basic miscalculation of maybe $1 to $2 billion in calculating the allowance for funds used during construction. I remember maybe five or six years ago, I wrote a letter to somebody in EIA pointing this out. I didn't get a response, and I don't know whether it's in the model, whether it has been changed in the model or not. But that's one example of data problems or matching economic concepts with accounting data.

Another problem is rate of return. You have your accounting rate of return, but I don't know who believes that accounting rates of return are true reflections of the economic or financial return, or the financial health or condition of electric utilities. So, that's another area where the off-the-shelf accounting data does not match the economic reality of what's going on. Accounting rates of return are just kind of plugged into a model like a production line, without really taking a close look at what they're supposed to represent.

Those are just a couple of technical points. The main question I'd like to address concerns assumptions about the structure of the electric utility industry and competition in the industry in the next 5, 10, 15 years. The conventional wisdom is that there will be increased competition, that regulation will not be needed. We're going to have all of these independent power producers out there competing with one another, and there's going to be a need for less regulation, no cost-based rates. And contrary to Leonard, I think the average cost, or levelized cost, is the more appropriate approach to use. It was appropriate to the industry in the 1970s, '80s, and before, and it's going to be appropriate to the industry in the '90s.

In the statement of purpose for the model, it mentions that "vertical integration of the electric power industry may be breaking down as a result of policy initiatives such as the Public Utility Holding Company Act in efforts to increase competition in power generation." Then it goes on to say, "as a result of this potential disintegration, separate companies working within distinct regulatory frameworks could be involved in each of three primary stages." Then it says, "therefore, these three stages of production will be modeled separately."

Well, it's that basic notion that there's going to be a radical change in the structure of the industry, and there's going to be increased competition. The preliminary evidence does not demonstrate that a competitive market structure in generation sales is likely to evolve or to be sustained. And there are three areas that I'm going to look to: the number of IPPs, the number of affiliate transactions, and the economies of scale in the industry.

Currently, the most recent data (which I believe are from 1990), show that about eight percent of the electric power generation was by independent power producers. Even the most optimistic forecasts for the future, the year 2010, 2015, expect this amount to go up by maybe 16 percent. What we're seeing currently is that there are about 170 independent power producers. Twenty-seven of these are electric utility affiliates. One well known consulting firm here in Washington, Hagler Bailly & Company, estimates that this number (170) will probably drop to 90 by 1995, just around the corner.

Other evidence that shows that we're not headed toward this competition in power generation markets is that of these independent power producers, three of the top ten are affiliated utilities. So, they're your traditional power producers. So, what you're beginning to see already is this shake-out of the IPP market. Even one of the most successful and truly independent power producers, AES, here in northern Virginia, has found itself in trouble. And many of the other previously successful IPPs have been bought out by traditional investment systems or their affiliates.

Now, another fac or that's weighing against the notion of increased competition in power generation is the number oı mergers that we've seen in the 1980s. You had Pacific Power and Light and Utah Power and Light. They're now PacifiCorp. You have Northeast Utilities acquiring Public Service Company of New Hampshire. You have Entergy which has announced plans to merge with Gulf States Utilities. And then last fall, you had the amendment to the Public Utility Holding Company Act that is likely to increase these mergers and affiliate mergers, and mergers among major traditional electric utilities.

Now, a third factor is simply the economics of what is going on, the economies of scale. The economies of scale are still significant in the generation market, despite the erroneous perception by some that our needs will be supplied by numerous small projects of idealized independent power producers. You know, currently, we're in a situation where the kind of power plants that are being built are peaking plants. It's easier for these independent power producers to go build a 25 megawatt or 50 megawatt plant.

However, when we get toward the end of this decade and into the next decade, we're going to be talking about large baseload units of 400 to 600 megawatts-pulverized coal units that are going to cost about three-quarters of a billion dollars. You're not going to find small independent power producers building these units. You're going to see the traditional investor-owned utilities, the big players today, around at the end of the decade, building and owning these facilities.

That's my view of what's happening, but this view is also supported by some of the heads of the investor-owned utilities themselves. Mark Buckley, the Vice-President for Corporate Development of Niagara Mohawk's subsidiary, HYDRA-CO., says that "the days of under-capitalized, small developers are gone. It's harder for them to do anything as the size of plants grows and the development time stretches farther. You need more financial substance now."

Also, Rehm Wooten, President of Duke's co-generation subsidiary says, "the ability to put together larger, more costly projects will turn an advantage for larger companies, such as those affiliated with utilities."

And finally, Dell Hock, who is the Chairman, President, and CEO of Public Service of Colorado, he sums up the likelihood of the long-run result of competition between independent and traditional utilities saying, "I still do not believe that the result will be a relatively large new group of entrepreneurs who would enter the wholesale power marketplace, resulting in significant price reduction for the mass of our consumers. Rather, a few entities, most of whom will be unregulated affiliates of major electric utilities, will dominate the independent power producer market."

And so, for the reasons I've stated, economies of scale, the evidence of merger, and the shake-out of the independent power producer market that we're seeing now and that goes on almost daily, I think the assumption or the context in which your economic model will be functioning will be in a world not much unlike the one we live in today in terms of regulation. Except for the fact that there may be more privately owned companies out from under FERC or state -- well, not state regulations, but FERC regulation for sure.

Thank you.

MR. GIELECKI: Thank you, John.

Our final reviewer today is Terri Carlock. Terri is the supervisor in the audit section of the Idaho Public Utilities Commission in Boise, Idaho. She does accounting and financial analysis, and has made presentations and testified on current issues of regulatory concern for the past dozen years. She is the chairperson of the NARUC Staff Subcommittee on Economics and Finance with the NARUC Group. And also, she has chaired the Ad Hoc Committee on Diversification.

Terri?

MS. CARLOCK: Thank you.

My comments today are based on my experience at the Idaho Public Utilities Commission and as Chair of the Economics and Finance Subcommittee of the National Association of Regulatory Utility Commissioners. Neither the IPUC or NARUC have taken positions on these models.

I would like to basically give a favorable review for most of the model presentation. I like the modular approach because it appears to allow the users to be as specific as they desire in certain areas and keep other areas general. From a regulatory perspective, that will be helpful because we don't look at every single issue. Looking at planning and policy issues going forward, I see that this could be very helpful for regulators and utilities alike. In this regard, I would like to be able to use this type of a model in the future when the PC version becomes available. At that time, the PC version, if it is user friendly, could make state regulation and utility comparisons easier for these planning purposes.

The Electricity Finance and Pricing sub-module and other sub-modules of the NEMS are on a regional basis. This allows specific options for different regional characteristics and regulatory environments. I'm not sure that the detail of the regions will be small enough to fully reflect the power sales and the transmission options for a region and between the regions.

For the Northwest Power Region in EFP, this region may provide a sufficient regional breakdown to provide for proper treatment of the Bonneville Power Administration Exchange Credit. This treatment is of concern for Northwest users because it is a credit allowed for certain customers, primarily the residential and irrigation customers, for the difference in the cost of service between the utility and the BPA base. EIA's documented views on how this type of credit would be reflected in the model would be helpful to Northwest users. A revenue requirement adjustment or identification of a different revenue source are options available to reflect this credit.

The EFP has the capability to employ a number of pricing options to calculate the wholesale transfer prices. I believe that a marginal cost-based pricing option is an important option for looking at the electricity pricing. This does not mean that the pricing method will be used or is used for ultimate consumer pricing, but it will be useful for policy and planning purposes for utilities, regional regulation, and state regulation. For pricing purposes, the EFP keeps track of new versus old generation and transmission capacity. This will be helpful in evaluating utility mergers and acquisitions.

In the area of pricing DSM from the Load and Demand Side Management Module, it is important to be able to look at the magnitude of the lost revenues, or to determine if lost revenues automatically result from DSM. This is an area of disagreement within regulatory jurisdictions. If DSM is used to meet load growth, the lost profit results from additional customer costs incurred. Recovery of these additional customer costs leaves the utility whole. The importance here is that the model have the flexibility to incorporate the different levels of DSM, lost revenues, the recovery and regulatory environments.

The return on equity and the overall rate of return are different for each regulatory jurisdiction. These differentials are picked up in the first year average and the DSM initiatives and incentives in the NEMS model. Expansion in this area in the future, or off-line analyses for these inputs, will make the model more user adaptable for comparative purposes.

The electricity pricing report will be useful in many settings. The output should be useful for regulators and policymakers to review utility mergers and acquisitions. A review of the specific data to the regional output will be a comparative measure to determine a sharing of the merger and acquisition benefits for fairness that are received by all utility customers, or at least a majority of the customers. This is an issue, and will continue to be an issue, for regulatory environments.

The ratio analysis for regional settings should be useful for comparison to utility-specific data in reviewing financial comparisons and bond rating reviews. I think this ratio analysis could be helpful in relating the IPP and NUG assessments.

In looking forward, I am anxious to see what the test results will be for this model and compare those results to some of the actual information that I have for the utilities in the Northwest. Thank you.

MR. GIELECKI: Art would like to take the opportunity to respond to the reviews.

MR. HOLLAND: I have one brief comment I'd like to make.

First of all, thank you very much for your comments to all three of you. I think what we have heard, particularly from Mr. Hyman and Mr. Kelly, is the reason why we have to have so much flexibility in this thing. We're not making assumptions, or we're trying not to make assumptions that the industry will disintegrate vertically.

What we are hoping to do is be able to make assumptions and make alternate runs to see what those effects could be. The devil is in the details and we still have some of the details, particularly data-related details, to work out, but that's the purpose for both the modeling on three separate levels, the three stages of production, as well as the choice of pricing algorithms. It is to give us specifically that flexibility so we could look at these potential future outcomes.

Thank you.

MR. GIELECKI: Thank you, Art.

Thank you to each of the reviewers, thank you very much.

We will now open the floor for questions. If you have a question, please identify yourself. Bill Townsend will have a microphone. Please speak into the microphone, so that your comments get into the transcript of the proceedings.

Any questions?

MR. HOLTBERG: Paul Holtberg, AS Research Institute.

You know, the title of this session is electricity finance and pricing. Ninety percent, 99 percent, maybe 100 percent of what you talked about was pricing. You might comment a little bit on the financing side, particularly in light of the comments you got from Mr. Hyman.

MR. HOLLAND: Early on, when we were looking at what this model was going to do, the suggestion was made by one of our colleagues that it would be better named the electricity pricing and accounting sub-module. It is heavier on the accounting and pricing than it is on the finance.

The financial end of it, we're reviewing now with an eye toward enriching the output of the model somewhat, but we're using simplifying assumptions right now because we don't want the assumptions that we're making about capital structure and cost of capital to get in the way of the results that policymakers are going to be using to make decisions.

The statement was made at a conference I went to just recently that one of the things that users of model output have to be cognizant of is all of the implied assumptions that go into those outputs. So, by maintaining a fixed capital structure throughout the range of the forecast and using regression algorithms for our costs of capital, we're simplifying those assumptions to keep them out of the way.

One of the things we would like to do is incorporate more of the operational and financial output of the data to make changes to the cost of equity capital. But this is something that has to be approached very delicately and carefully because we don't want this to get in the way of the output. The return on ratebase component of price is roughly 10 or 15 percent, I would say, of the price of electricity, maybe a little more. So, that's the potential part of the price of electricity that we're tinkering with when we do that and we want to be very careful how we approach that.

MR. HOLTBERG: You know, I understand that you've got to deal with certain aspects of the modeling structure, you only have so much time and resource and all that other stuff that goes on. But you made a little point in there saying, "we don't want the financing to get in the way," which strikes me somewhat funny because the financing is a major determinant of what your prices are going to look like. And the financing is going to vary by type of generator, by the financial conditions in that region, by a lot of different rules that are set on utilities versus non-utility generators.

You can't just throw that stuff out the window, and I think you really need to take a hard look about how that's going to evolve in the future and what it means for pricing.

MR. HYMAN: I just wanted to thank you for that question because what disturbs me in terms of a number of conferences and government committees I seem to get myself into inadvertently, is that people don't realize that a lot of decisions are made for purely financial reasons. Which may leave you with what you may consider to be completely sub-optimal results from the standpoint of the economy or from the standpoint of customers.

People are simply not going to go stick their necks out, making decisions that will benefit customers and may very well be detrimental to the securities holders. So, you can't get around it, and I'm convinced some close-downs of nuclear plants now are going to be for no other reason than if you can close the plant down and get your money out, it's better than running the plant, even if customers don't benefit. So, you know, I don't think it can be left out.

MR. HOLLAND: Let me respond, if I could.

Yes, you're right. The problem here is on several levels. One is, it's a very difficult thing to forecast the cost of capital. Even if you look at either equity or debt, forecasting that in a 20-year model is extremely difficult. And the results of forecasting wrong could overshadow doing everything else right. So, that's the reason I say we don't want erroneous output that overshadows all the other things that we hope we're doing right.

Another level is the relationship between utilities and non-utilities and their respective costs of capital. There is very little agreement in the literature on generically what your capital structure will do to your cost of capital. And then, when you get into the specifics of utilities versus non-utilities, it's even muddier. So, it would be nice to be able to look at the utility cost of capital and the non-utility cost of capital and say that's an important output to whether the utilities are going to build their own generating capacity or purchase the power from nonutilities.

But again, we don't want errors in this area, because of the difficulty of forecasting the cost of capital, to overshadow the decisions that are being made in other parts of the model. So, we're looking at it. We're approaching it very carefully. But I think the watch word here is "very carefully," making sure that whatever we do, we do it right. And that the assumptions that are implicit in the way we do it are easy for the decision makers to use in their analysis of the output from the model.

MR. ROGERS: Scott Rogers, University of Toronto. I have a question for Mr. Kelly and for Ms. Carlock.

If I understood you correctly, Mr. Kelly, on the economies of scale, you said something like three-quarters of a billion dollars for a baseload coal-fired plant in the neighborhood of 500 megawatts works out to something around $1,500.00 a kilowatt the latter part of the decade?

And if that's right, would Ms. Carlock agree that that's reasonable for Idaho coal?

MS. CARLOCK: As far as the actual dollar amounts, I know that for some of our utilities, it is somewhat less than that. But those are ball park figures that we have received in avoided cost proceedings.

MR. GIELECKI: Anyone else? Any more questions?

MR. BUTLER: Jack Butler, Argonne National Laboratory.

Could you tell us what facilities the submodule offers for evaluating different types of rate design, such as time-of-use pricing, declining block rates, various allocations of customer charge or energy charge? Are the interactions with the demand submodule such that those submodules would respond to such varying rate designs?

MR. HOLLAND: That's a good question. The EFP will not differentiate rate designs and the time-of-use rates will not be represented within the EFP. There's a good reason for that. What the Electricity Finance and Pricing Submodule is going to get from those other submodules is the result of the implementation of demand side management programs and the costs that are associated with them. The reason that we would want to incorporate time of-use-rates within the model would be to test or to model the penetration of demand side management techniques that are dependent on those rates for penetration.

The Load and Demand Side Management Submodule will make the adjustments to the load curves for each customer class, for each demand side management program that's implemented on a competitive basis, by the Electricity Capacity Planning Submodule. If we were to turn around and try to calculate different rate structures within the Electricity Finance and Pricing Submodule, the demand modules would then be getting bad pricing signals from us, because those adjustments have already been made in what we're seeing.

Does that answer your question?

MR. BUTLER: It does answer it. I'm not sure it's a satisfactory result though.

MR. HOLLAND: I can't address that.

MS. SULZBERGER: Virginia Sulzberger, NERC.

Where are you getting the transmission expansion plans and distribution expansion plans that you are trying to finance in your model here, and cost out and price?

MR. HOLLAND: Transmission expansion plans will come from the Electricity Transmission and Trade Submodule. The distribution expansion plans will be calculated within the Electricity Finance and Pricing Submodule.

How we translate transmission capacity expansion costs into prices is probably the best reason why I agree with Mr. Hyman that it would be nice to sit down for two years and wait until the dust settles.

We're really shooting at a moving target with what the FERC has been doing with transmission pricing, with opportunity cost pricing, and incremental cost pricing. The evidence that I've seen and that I'm aware of is that the PENELEC cases and the NU cases have resulted in orders that will result in the majority of the industry using embedded costs for transmission pricing. That's probably what we'll use initially.

The distribution costs of capacity expansion, because that's really the only pricing algorithm we're going to be using initially in the distribution stage of production, will also be costed out and priced on an embedded cost basis.

MR. DUKERT: Joe Dukert. I'm an independent energy consultant.

It's a minor matter, considering all the other problems you have, but where do you expect to get the data for your nuclear plant decommissioning costs?

MR. GIELECKI: Cost estimates for de-commissioning, are filed with the Nuclear Regulatory Commission. That's where the data come from.

MR. DUKERT: Well, I'm sure you realize that around the country, the estimates by individual utilities of these costs are varying all over the lot, changing from year-to-year.

MR. GIELECKI: Yes. Yes, okay, now I understand your question better.

They, in fact, increase by orders of magnitude every time there is a new estimate, and there are various reasons for that. But that notwithstanding, what we will do is continue to track those cost estimates as they are made. They are always made in overnight costs and, therefore, they are made periodically. I don't think there's any set time to when they are made available, but it seems like every couple of years or so by either the Nuclear Regulatory Commission or an engineering firm.

Does that answer your question?

MR. HOLLAND: One of the suggestions that has been made in the liability that's going to be entered as a line item in the Electricity Finance and Pricing sub-module is to take these estimates and put an annual escalator on them, to keep moving that liability on a year-by-year basis. Other than that, within a modeling framework, that's really all we plan on doing right now.

MR. GIELECKI: Any more questions?

I thank you very much for your interest and have a nice day. Thank you.

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