NEMS REVIEW

RENEWABLE FUELS MODULE CRITIQUE

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That was one paid political announcement about what Tom is going to say. Here's my second one, and then I'm through with the paid political announcements. We applaud the EIA for putting an emphasis in NEMS on renewable energy. It's been omitted from many of the modeling efforts in the past, both at EIA and elsewhere. It's something that I think most of us recognize has got a large potential, and it's time to start paying some attention to how to model it.

I'd also say that it is very difficult to model most, if not all, of renewable energy forms, because of the large number of non-economic factors that affect almost all of them, and that's why you heard Scott say some of the things that are going to be done exogenously, at least in this initial version of the model, and we'd have to endorse a lot of that. But we also want to establish long-range attempts to move more of the factors into the modeling arena, so that, in fact, we can do policy analysis and sensitivity analysis and what have you within the NEMS structure.

The Renewable Fuels Module itself, I don't have a whole lot to say about it, except one thing in general, I think it's good that the NEMS structure is going to allow the eventual incorporation of all renewables, either endogenously or with exogenous estimates as necessary. The renewable fuels module makes that provision for the data inputs right now.

I think it's important to recognize that the Renewable Fuels Module really allows you to put in the inputs and to change the cost and technology characterizations and resource costs over time, but doesn't actually do the competition of the renewable fuels with other energy sources. That doesn't take place in the Renewable Fuels Module. That's a subject that's really addressed by all the other end-use models, and electricity market modules, and petroleum modules within NEMS. And so, most of the comments that I have today here are really confined to the Renewable Fuels Module, and, therefore, to the inputs and how the characterization and resource characteristics change over time.

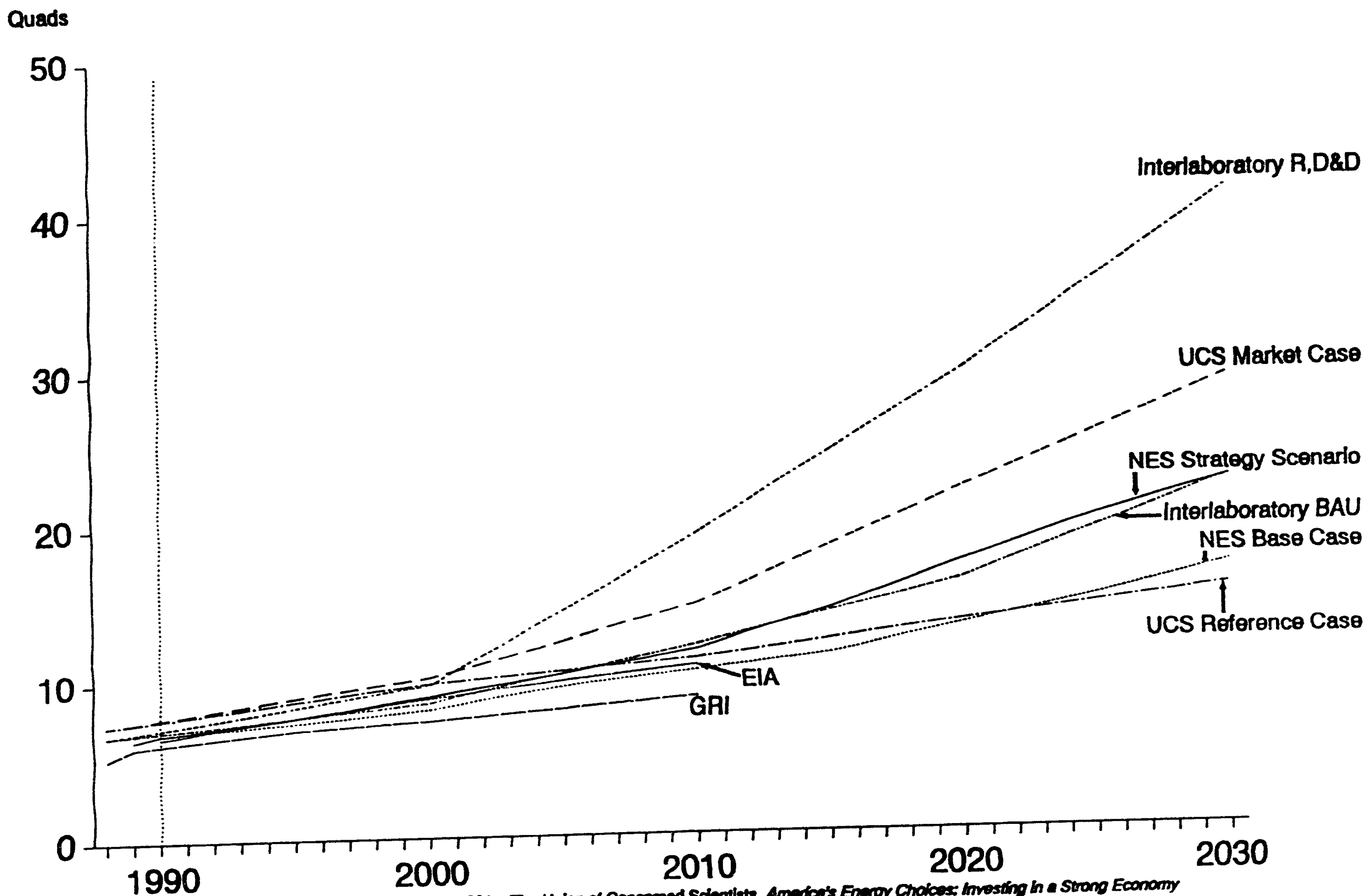
One more note before starting is that, you notice I said Renewable Fuels Module CDR; we haven't seen the module itself, and coding or running it or anything like that, so, really, we are commenting based upon the component design reports, which I believe is basically true of everything you are hearing at the conference today.

The last comment is minor. I don't have with me a diagram of the RFM itself, there are a couple of boxes in there that are not real entities, as we understand them in the final model, and, therefore, perhaps, should be omitted from the diagrams of the Renewable Fuels Module.

One last thing is, I'm going to go down to the submodules and talk a little bit more specifically about each of them. I've made an attempt, not totally successfully, to try to constrain my comments to things that we think we have some ideas on how to change them for the good. I think it's very easy, as we all know, to comment and say, oh, this is wrong, we know it doesn't work this way, and then be lacking in any ideas on how to fix it. So, I hope I will be able to provide some constructive ideas on some of these things.

The Hydropower Submodule, a few quick individual comments. First of all, as we read the CDR, there's no provision in there for minimum stream flow constraints. That is, if you've

Renewable Energy Demand Forecasts



Sources: *National Energy Strategy Technical Annex 2*, DOE/S-0086P, June 1991; The Union of Concerned Scientists, *America's Energy Choices: Investing in a Strong Economy and a Clean Environment, 1991*; *The Potential of Renewable Energy: An Interlaboratory White Paper*, SERI/TP-260-3674, DE90000322, March 1990; Gas Research Institute, *Baseline Projection Data Book, GRI Baseline Projection of U.S. Energy Supply and Demand to 2010*, 1991 Edition; Energy Information Administration, *1991 Annual Energy Outlook With Projections to 2010*, DOE/EIA-0383(92), January 1992

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RENEWABLE FUELS MODULE CDR

- The RFM will allow the eventual incorporation of all significant renewable energy technologies.

- RFM scope is limited to data input and resource/technology updates.

- Undefined boxes in CDR diagram of the RFM
  - "Renewable Electric"
  - "Dispersed Generation"

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HYDROPOWER SUBMODULE CDR

- No provision for minimum stream flow constraints (easily incorporated).

- Dispatching algorithm appears reasonable, but it is not clear to us how it comports with the vertical slice disaggregation of the load duration curve in the ECP.

- Capacity expansion forecast should be compared to INEL's ongoing site-specific examination of future hydro capacity.

- Run-of-river hydro excluded.

got a dam or a reservoir that has to continue to flow through, because of constraints on size of stream flow, that's not currently provided for in the model in terms of the dispatching of hydropower, and it could be easily incorporated by simply relegating that minimum stream flow down to base load and then following the current dispatching algorithm that's suggested in the CDR.

The dispatching algorithm itself sounds very reasonable. Basically, it consists of figuring out what the electric power capacity of the hydrosystem is, and moving it up in the load duration curve until all the energy is consumed, so it just fits right in. So, you just slide it up until it fits in the right place in the load duration curve, and that's simply done first, and then you've got a remaining load duration curve that you use for the competition of other technologies.

It appears very reasonable to us. About the load duration curve, I think Scott mentioned a minute ago there's an attempt within the Electric Market Module to divide it up vertically, based upon different periods of time during the day. How this dispatching comports with that is not clear in the CDR. It's pretty clear to us that there are several very reasonable ways to do it. We are interested in seeing how that comes out.

The submodule doesn't really address capacity expansion endogenously, and we think that's reasonable because of the large number of factors that simply can't be accounted for in any reasonable way inside of NEMS at this point in time.

However -- and, we think the numbers actually that are suggested in the CDR right now for future capacity expansion are also reasonable, but we think that it ought to be reviewed with a study that I understand Idaho National Energy Laboratory (INEL) is conducting right now for CE, and those comparisons should be possible to be made in the summertime, I believe.

Finally, run-of-river hydro is excluded, not a big deal. I've seen one study that suggested up to ten megawatts or something like that. Perhaps, it could be included later, but it's not a big deal.

I'm not an expert in geothermal, but some of my people tell me that there is a significant problem here. This is one for which I don't really have a good solution, but I'll make some recommendations as to things that could be done that will get us part of the way.

As we understand it, the database developed and used for these sites for geothermal that are going to be used in developing a supply curve here in the Geothermal Submodule are really aggregated from a study done by Susan Petty for Sandia. Basically, what they have is something like 600 sites, and they took them and combined them down into, I think 58 sites, and they did that geographical proximity, based upon geophysical similarities, temperatures, etc., or expected temperatures and flow rates.

It was a fine study, as far as we can tell, for costing purposes, but it seems like it is being used here beyond what it was originally intended to do. In fact, some of the sites, the aggregate sites, contain both developed and undeveloped actual sites. Therefore, the capacity expansion module here in the geothermal submodule -- the capacity expansion algorithm, really relies heavily on whether or not it's developed or undeveloped, and it's a little complex given

GEOTHERMAL ELECTRICITY SUBMODULE CDR

- The SNLA (Petty) data base sites are aggregates based on site similarities for costing purposes.
  - Combining developed and undeveloped sites confuses capacity expansion constraints.
  - Combining distant sites confuses transmission cost estimates.
  - Combining sites confuses enthalpy decline algorithm. Decline could be tied endogenously to fluid withdrawal.
- Place sites on the supply curve using Levelized Energy Costs.
- Track solid wastes (drilling muds and heavy metal precipitants during flashing) and H_2S in production and drilling.

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the aggregation level that's actually in the database that they are using -- complex and, perhaps, not justified.

So, one recommendation there is simply to simplify it. Another recommendation on all of these points regarding this database is to check with Susan Petty further about exactly what went into that. We did some of that preliminarily, and she had some concerns.

Some of the sites are, in fact, not right on top of each of other. Some of them are 200-300 miles apart, that is, actual sites are aggregated to one site. So, therefore, when you start talking about transmission costs, hooking the sites up to the grid, you've got some problems with the aggregation.

And also, there's an enthalpy decline algorithm that basically specifies a starting date for the enthalpy decline. That's also problematic with these combined sites, inasmuch as some of them haven't been touched, and some of them are already under development.

We would suggest, perhaps, and I guess there's actually another problem, in that the starting date is really a function of how you are drawing the reservoir down, and, perhaps, that's a way that the enthalpy decline should be modeled.

Two more small points. The supply curve that's developed for the Geothermal Submodule: the sites are placed on it based upon capital costs only. It's probably not a bad approximation, but it's a fairly simple matter, especially given that you've got two different plant types, flashing and binary, to combine them -- to do the levelized energy cost calculations and place them on the supply curve in that way.

Scott mentioned that they are tracking CO_2. Obviously, hydrogen sulphides is a significant emission from geothermal, as are some of the drilling muds and the participates that come out from the fluid. We know that NEMS doesn't track those kind of things as a whole, but we'd recommend some way to at least make sure that those outputs are available to users of the module.

This slide is actually based upon a review of the Ethanol Biomass Supply Submodule. We've read the ones on MSW and wood, and I'll make a few small comments at the end of this. I don't have a slide on those per se, but let me just do this one first.

Ethanol. Its initial priority in the CDR is on corn to ethanol, which is obviously the current day production; the ethanol that you are using in your own gasoline is largely derived from corn. We think it's appropriate to start there.

The CDR, though, describes two supply curves, one for corn to ethanol, and one for energy crops to ethanol. That's not bad in terms of feedstocks, at least supply curves are for the feedstocks and then they go to a conversion plant.

But, the problem is when you take diverse energy crops, switch grass, short rotation woody crops, poplar, sorghum, whatever, to the same conversion plant for all kinds -- for all those different types. In other words, you've got one energy crop supply curve and you are

BIOFUELS SUPPLY SUBMODULE CDR

- Initial priority on the representation of corn-to-ethanol is appropriate.

- A single energy crop supply curve will not capture significant differences in conversion - yields, costs, by-products.

- All energy crops, corn, and waste feedstocks with their conversion processes could be aggregated into a single ethanol supply curve for each region.

- ARIMS is driven by agriculture cost minimization only:
  - lacks ethanol criteria
  - demand/refinery locations
  - state incentives
  - non-attainment areas

- A competitive market algorithm instead of fixed market shares will prevent price anomalies.

- Taxes must be considered in amortization equation.

taking it to one conversion plant. You've got trouble by the diversity of transportation costs, of conversion costs, of conversion yields of the byproducts that come out of the different types of crops.

What we'd suggest here is really in the third bullet there: don't aggregate those energy crops until you've gone through the conversion plants and constructed a supply curve for ethanol itself, as opposed to for the feedstock. And, if you did that, in fact, you could combine the energy crops, as well as corn, and current existing waste feedstocks that are used, all into one ethanol supply curve, as opposed to feedstock supply curves.

One other thing I'll mention that's not on here, that's not on the slide, as we read the CDR there is the vintaging for these plants that doesn't exist. It looks like there is one conversion rate for each time period, but they don't seem to be tracking when the plant was built, and, therefore, retaining the conversion rate for that plant as time moves forward. That needs to be looked at.

As Scott mentioned also, they use the model at the University of Tennessee called ARIMS, for the agricultural modeling. There's no feedback between NEMS and that model, other than man/machine type feedback. At this level, we think that's probably appropriate. It does introduce some problems in terms of the fact that what this model does is really look at the agricultural sector and the demand for food crops with these energy crops being added as a new entity into it, well, actually, over the last couple years they've been added.

The model, because it looks at food crops, is driven by the international demand for food crops as well as by some of the factors that influence ethanol conversion plant siting, and not just the agricultural criteria. In other words, where are the refineries? What are the state incentives for ethanol, which, obviously, could be a big factor in variations, and should be a part of the ARIMS, and even non-attainment areas. These last three things we think would be fairly facile to incorporate in ARIMS, and we'd suggest they be looked at.

There is also, in developing the supply curves, a set of market shares that are specified exogenously in terms of, you've got a refinery and you've got a couple of demand regions -- or, supply regions for the feedstocks that are feeding into the refinery, and the shares over time are the same and they are fixed. In other words, you say, from Region A I'm going to get 14 percent, and from Region B I'm going to get 37 percent, and they are fixed over time.

The problem that we see with that, of course, is that you could get to the point where you are constantly demanding feedstock from a region that has ever-increasing costs because you've moved up the supply curve, and you've got another region over here where your market shares aren't asking for very much, and it's down low on its supply curve, and, therefore, you could get significant price differentials within the model as it is currently constructed.

The answer is, of course, you build some kind of competitive mechanism between the different supply areas. There's different levels of complexity at which you can do that. We are not suggesting that you make it extremely complex, just that you do something at least to keep the model in some kind of equilibrium.

CONCLUSIONS

- Good job overall of setting up framework for including renewables.
- Most serious conceptual issues are in the biofuels module.
- Must ensure other NEMS modules handle renewables appropriately.

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Finally, in the amortization equation for the capital costs in the CDR, you multiply the capital costs by a capital recovery factor. The capital recovery factor is simply based upon discount rates. It should, in fact, include tax considerations, and it should include depreciation of the plant, etc., That's not in the model, at least not in the CDR.

That comment actually applies, not just to the bioethanol submodule, but also to the MSW submodule, as best we can determine. The equation is just based upon discount rates, instead of the tax situation. It's tax rates and depreciation rates, etc.

Just some verbal comments on the MSW, again, we think that the exogenous specification of the MSW capacity and its growth over time is reasonable. There's too many non-economic factors that really drive the situation. A lot of plants have been canceled recently. You can't do it endogenously within any model that we have at this point in time.

I'd also say that even trying to do it outside the model is extremely difficult, given the lack of data that exist on available MSW supplies, where they are, what their constituency is, and that's something that I'd hope the EIA will play a role in developing new data for.

On wood, just one short comment, short rotation woody crops are included in the supply curve that they developed for wood, but if you did what I was suggesting in bullet three there, you'd also have short rotation woody crops here for the bioethanol, and that needs to be considered in terms of the competition between these different fuel sources, or between the different end uses, of the fuel sources.

Overall, as I said, the Renewable Fuels Module is kind of an interesting way to keep all the renewables inputs in one place. I think it seems to be working pretty well. We had some doubts originally about why you were putting electricity resources with buildings resources, etc., when you put all the renewables in one place, but it seems to be a good working concept, so we are pleased with that.

I think the most serious issues that I've addressed today were in the biofuels module for ethanol, but they are not things that can't be improved upon fairly easily, I would guess.

And, I'd make one last point before I sit down: as I said when I started, the renewable fuels module is just where you get the inputs and the updates over time. The real gist of the problem is how those things compete in the electric market module, in the residential module, in the commercial and industrial, etc., and that's where we would hope considerable effort is being spent.

Thank you.

MR. SITZER: Thank you, Walter.

So, let me turn to my second reviewer, who is Mr. Tom Hoff; Tom has been an Electric Utility Consultant for the past 8 years, doing much of his work for the Pacific Gas & Electric Company in the area of photovoltaics.

His research has ranged from system-wide PV economic evaluation studies, to targeted distributed generation work, to alternative strategies that might be used to integrate distributed generation into the utility network.

Tom has a B.S. from California Lutheran College in Mathematics and Computer Science, and an M.S. from Washington University, St. Louis.

Tom, please go ahead.

MR. HOFF: This afternoon, I'll be commenting only on the solar submodule of the renewable fuels module, with an emphasis on PV, since that's been where my experience has been.

Most of the work I'll be presenting is based on work done for Pacific Gas & Electric Company over the past number of years.

There are two things I'd like to cover today, and two major points; the first major point deals with the capacity relief capabilities of PV, and how PV can relieve capacity constraints within the utility; and the second is to suggest some desirable NEMS policy analysis capabilities. So, I'm dividing my talk in, really, two parts.

This first model is a very simple model, and, yet, a very powerful model. A couple of years ago, there was a utility PV conference in Italy that drew together executives from utilities, and one of the most important things that I think that came out of that conference was this diagram.

When I began working with PG&E about 8 years ago, I spent a lot of time on that point number three, peaking power. We did a lot of studies looking at the match between photovoltaic output and utility system load. We did it with actual load and actual output from a PV plant located in the center of California. We did it with simulated data from 13 sites over four-year time periods, with six different plant configurations. I mean, we did a lot of analysis of looking at load match, and in every instance the answer was the same, for PG&E photovoltaics was a great match to the utility load.

At the same time -- I was in R&D at that time -- at the same time, we were looking at how we might integrate PV into the utility network, others within the utility were using PV within the utility network. That's kind of ironic, I guess, as to the way it usually works. R&D thinks about what you want to do and the other parts of the utility do it.

That's where we see the early applications. People within PG&E were using photovoltaics for small-scale power applications, not grid connected, but power applications. For example, people in the Gas Department had little photovoltaic systems that were used to power gas flow computers. They used photovoltaics in remote areas to give cathodic rejection.

One of the real innovative uses, I thought, was the use at PG&E's Heloms Pump Storage Facility. What they did was, they replaced existing equipment, I believe it was batteries and diesel generators, to power the communication setup of the pump storage facility and some of

NEMS Users Conference
Renewable Fuels Module
Solar PV Submodule

Tom Hoff
Consultant to Electric Utility Industry

(Presentation is based primarily on work performed for Pacific Gas and Electric Company)

February 1, 1993

Overview

- Capacity Relief Capabilities of PV

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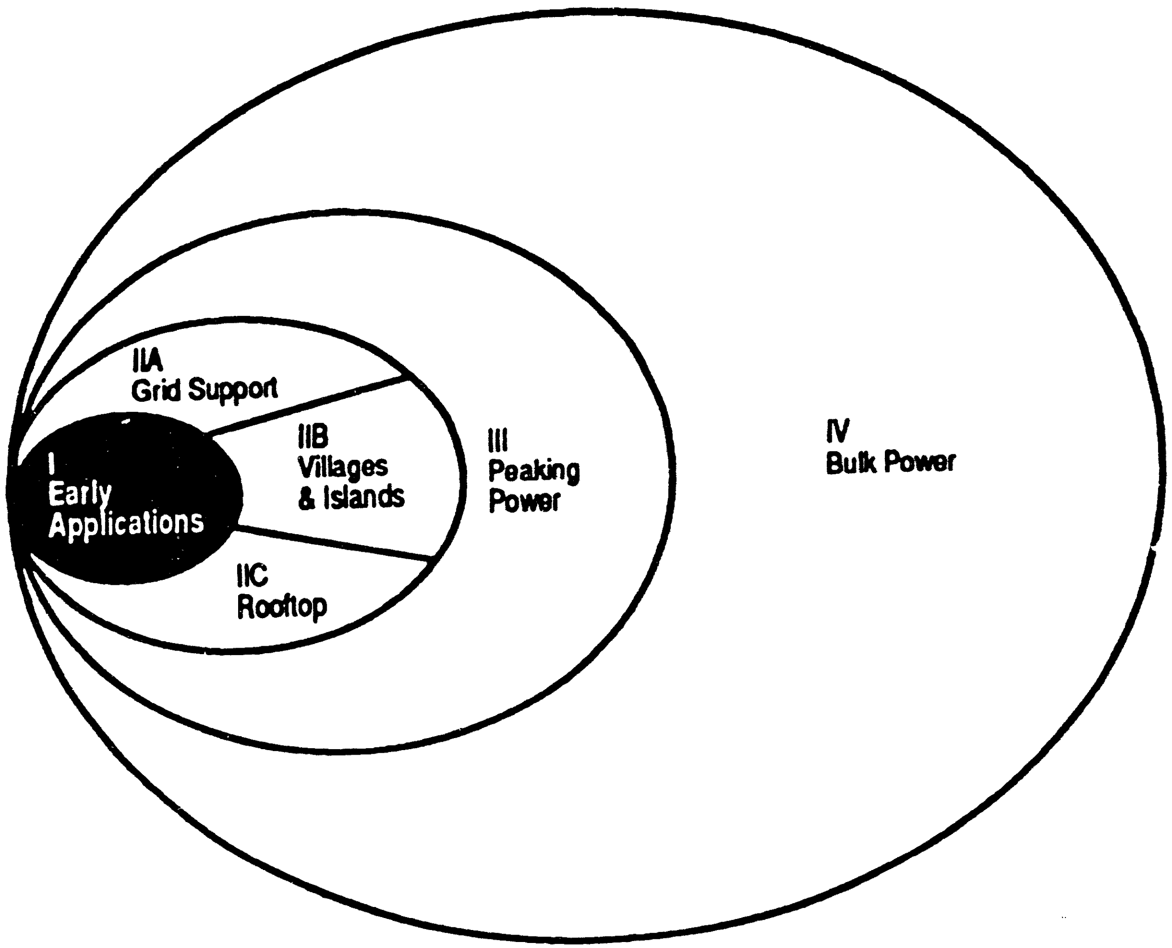
- Desirable NEMS Policy Analysis Capabilities

Paths of PV Market Integration



the control with a photovoltaic system.

And, the list goes on about other early applications.

Now, from a NEMS' perspective, those are insignificant, they don't amount to hardly any power, but, yet, from a market integration standpoint those have become very critical, and they really are the first step of PV being integrated into the utility network.

As you see in the diagram, the second phase is a three-phased approach. There is grid support, villages and islands and rooftop. Now, obviously, from the perspective of the United States, we don't have a lot of village and islands, so you can kind of block that one out of your mind for NEMS' purposes, but those other two points, I think, are crucial, and I think it is very important for NEMS to recognize that.

Grid support, in essence, is the idea, since photovoltaics is a modular technology, of taking photovoltaics and placing it where you need it within the utility grid. You do this to reduce your transmission and distribution upgrade costs, to reduce system losses, to provide voltage support, and several other distributed benefits. That's the idea of grid support.

Rooftop is just the idea that you put PV on people's rooftops, businesses, residences, wherever, but the same goals of grid support can be accomplished by the rooftop approach, where you have many little PV systems to support the grid.

Now, the reason this is so important from a NEMS' perspective is, that's going to be the first major area that photovoltaics enters the utility network, and it may be a significant one for quite a while because you can gain a lot of extra value potentially by citing these systems within the utility grid where you need it.

The third step of market integration is this peaking power, and, finally, who knows when, bulk power.

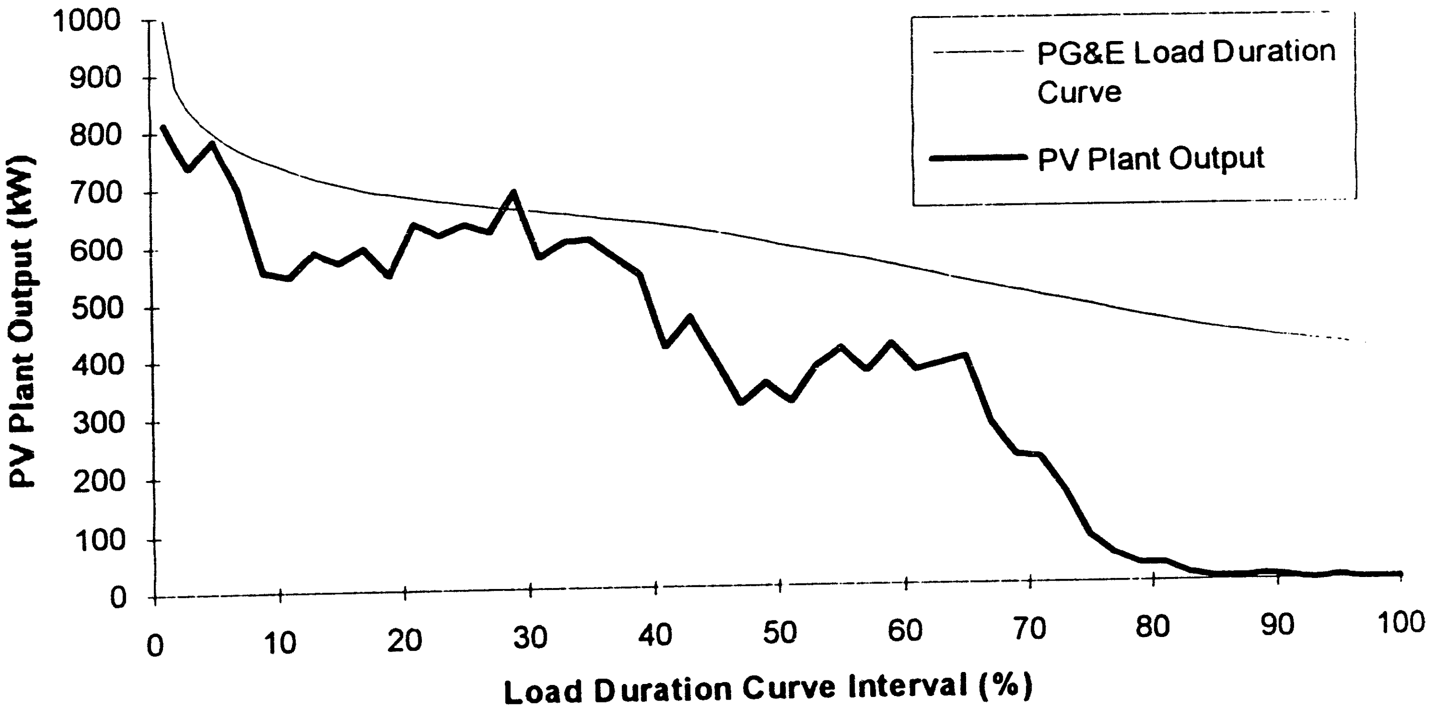
As I said, my first point I wanted to talk about is the fact that photovoltaics can provide a utility with additional generation capacity, additional capacity. In these next several slides, look at it from a variety of different angles. This first slide looks at the capability of photovoltaics to provide generation capacity.

What I've done in this diagram is, I have the load duration curve and associated with that load duration curve is the average PV plant output.

Rather than going into all the details of how the graph was put together, the bottom line of the graph is at PG&E's peak loads, that is, the left side of the graph, photovoltaic output is highest. And, that's very important because, in terms of generation capacity almost 100 percent of a utility's generation capacity comes in the top 100, 150 hours, so most of it comes from those hours, so that's when you really care about it. So, PV matched PG&E's load from a systems perspective.

If you take your magnifying glass out and you move down from the system perspective

PV Can Provide Utility with Additional Generation Capacity



into the distributed utilities perspective, or the local perspective, you have another case. This graph has a lot more information on it than I'd like you to get out of it, so let me make a few points.

If you look at the bottom two bars of the graph, you'll see that those represent energy value and generation capacity. Those are what you would get from a PV system, just in terms of system value, if you only had a system value.

If you site a PV plant at a distributed location, you have a wide range of what kind of benefits you can get, and these three bars reflect the fact that, depending on your economic perspective you can have very significant benefits that are distributed benefits.

At the lowest level, the distributed benefits are a little bit more, that's the lowest level at the far left of the graph, you can have distributed benefits that are a little bit more than traditional benefits.

On the right of the graph, if you go all the way, you can have significantly greater distributed benefits that are even greater than your system benefits.

The point of this is twofold. One, if you look at the legend of what those benefits listed are, many of those benefits are capacity based, they are not just energy based. So, there again, the PV provides capacity value to a utility. So, that's one aspect of it.

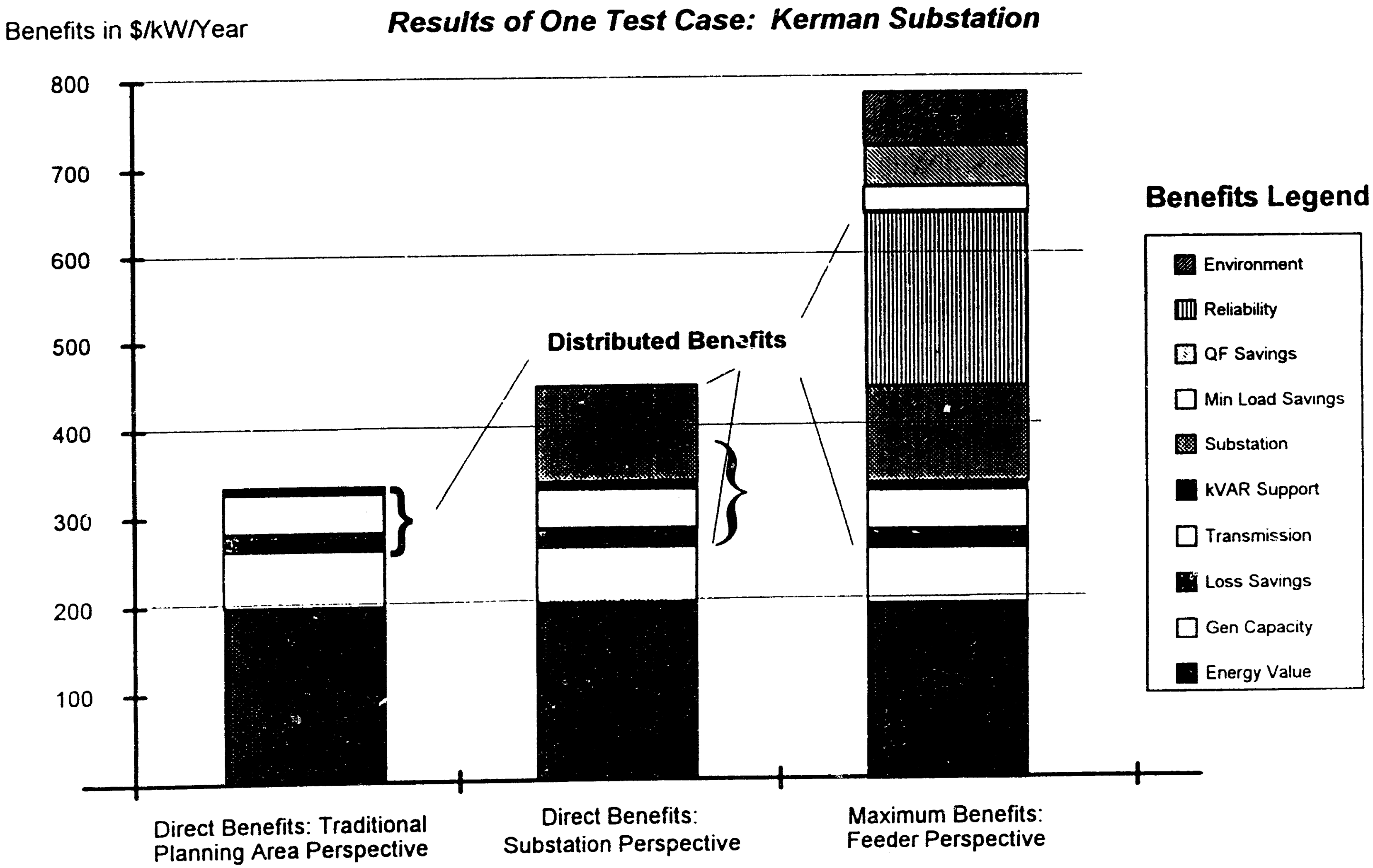
The second aspect of it, and, perhaps, even more importantly, is, there is a large benefit that you can get from distributed photovoltaics that many other electric generation technologies are not going to give you, and I share Walter's concern, or however you put it, that NEMS would be very careful in how they do the costing comparisons of a technology such as this versus other generation technologies, and there needs to be some way to reflect this. And, I recognize that that's a very big challenge, because you don't know what the distributed benefits are at the different locations, but they exist and there should be some way to reflect at least a place holder that these kinds of technologies have those benefits.

Just for illustration purposes, I included this slide. We recently completed a study with PG&E that looked at the use of photovoltaic on a standard two-story commercial building that had about a 100 kilowatt load. And, as we did the analysis, we came up with a very interesting result, that two-thirds of the energy saving, two-thirds of the total bill savings from a customer's perspective are energy related and one third are demand or capacity related.

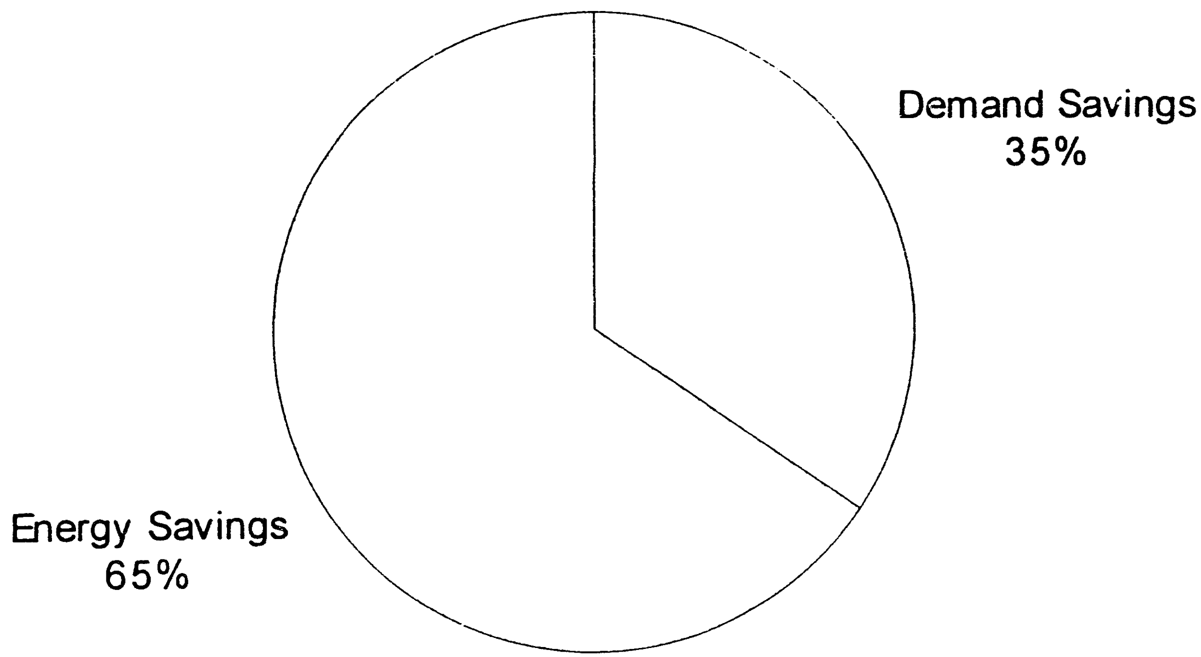
The significance of that is that it depends on the way that the demand savings are calculated. The utility charges demand charges to customers based on their maximum half hour monthly load during each month of the year and maximum half hour load during each month of the year for each peak period.

The point is, that's one small number throughout the entire month, and in order to get a reduction in capacity, or a reduction in demand savings, you have to reduce all loads down below that peak number.

PV Can Provide Utility with Distributed Benefits



PV Can Reduce a Customer's Utility Energy and Demand Bills



Results for One Year for One Test Case: PV system rated at 1/5 of peak load

And, I included this slide just to show that it's a surprising result, but PV did this for the correct customer in PG&E's service territory, of reducing this demand on a customer basis. So, you see PV working in terms of reducing capacity requirements on a system basis, on a local basis and on a customer basis.

You may be asking yourself, and you should be asking yourself, well, this is nice, PG&E's one little -- well, one big utility, but little compared to the rest of the nation, how does this compare to the rest of the nation?

Richard Perez, working with NREL, has been doing a very interesting study looking at selected utilities throughout the nation. I think he lists about 20 different utilities, so I have just taken a sample of the utilities he's looked at.

If you look at the results, you see that this is not a unique phenomenon just to PG&E, but if you look at the capacity that PV provides to the utility, this being defined capacity as a percentage of plant rating, we found in PG&E there is 75 to 80 percent of the plant capacity provided to the utility; look at the midwest, Kansas City, you have 70 to 75 percent; a northeast utility, 70 to 75 percent; Minnesota utility, 65 to 70 percent; Atlanta Electric, a southern utility, 65 percent and so on, and the point is, contrary to what you would think, photovoltaics matches utility loads, not just in the west, or the southwest, but at different points throughout the nation, and it's dependent upon the match between the load and the solar output.

The second aspect of my talk I'd like to comment on is to think about some policy considerations that would be nice to include in the NEMS model, and I've divided these policy consideration issues into two basic areas. The first is the tax issues, and the second are environmental regulation issues.

Under tax issues, the first point is tax credits. Now, that's pretty straightforward. It's a credit based on either the capacity of the system or a credit based on how much energy the system will put out. I don't really need to comment further on that.

The second point is the treatment of capital versus expense dollars. In this next slide, I have plotted the relative comparison of the distribution of costs for two types of plants. Now, this slide does not suggest that these two plants cost the same, obviously they don't, the point is the comparison between the distribution of costs.

If you look at a solar plant, most of the costs are capital related, not surprising, and a very small percentage are O&M related. If you look at, on the other hand, a fossil fuel plant, most of the costs are fuel and maintenance related, and a very small portion are capital related.

So, what? The "so what" is, from the utilities perspective, capital dollars cost utilities more than expense dollars because of tax reasons, and this may be one area where NEMS could consider what kind of policies can be used if desired to put those two different technologies on a comparable basis, and so that's one type of policy consideration that could be used.

A third policy consideration is even more subtle, it's an ownership issue. In this figure, I show the comparison between the cost of a PV plant to a utility and the value, and, again, the

PV's Generation Capacity at Selected Utilities

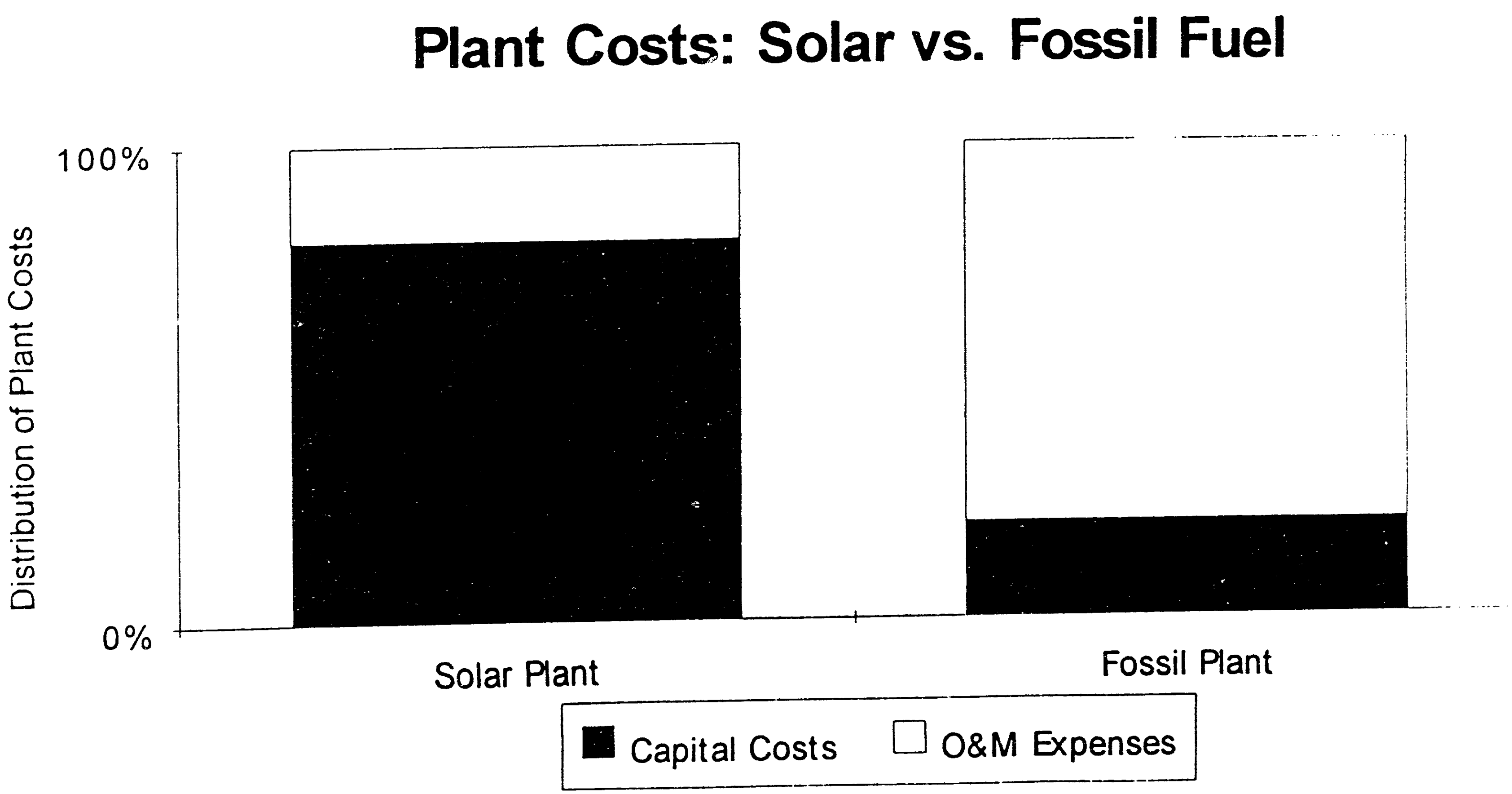
- **PV's generation capacity is not limited to a westcoast utility such as PG&E**
- **Capacity (as Percentage of Plant Rating):**
  - Pacific Gas and Electric Company: 75% to 80%
  - Kansas City Power and Light: 70% to 75%
  - Con Edison: 70% to 75%
  - Norther States Power: 65% to 70%
  - Atlanta Electric: 65%
  - Great Lakes: <50%

Note: these are preliminay results based on work sponsored by NREL, performed by Richard Perez

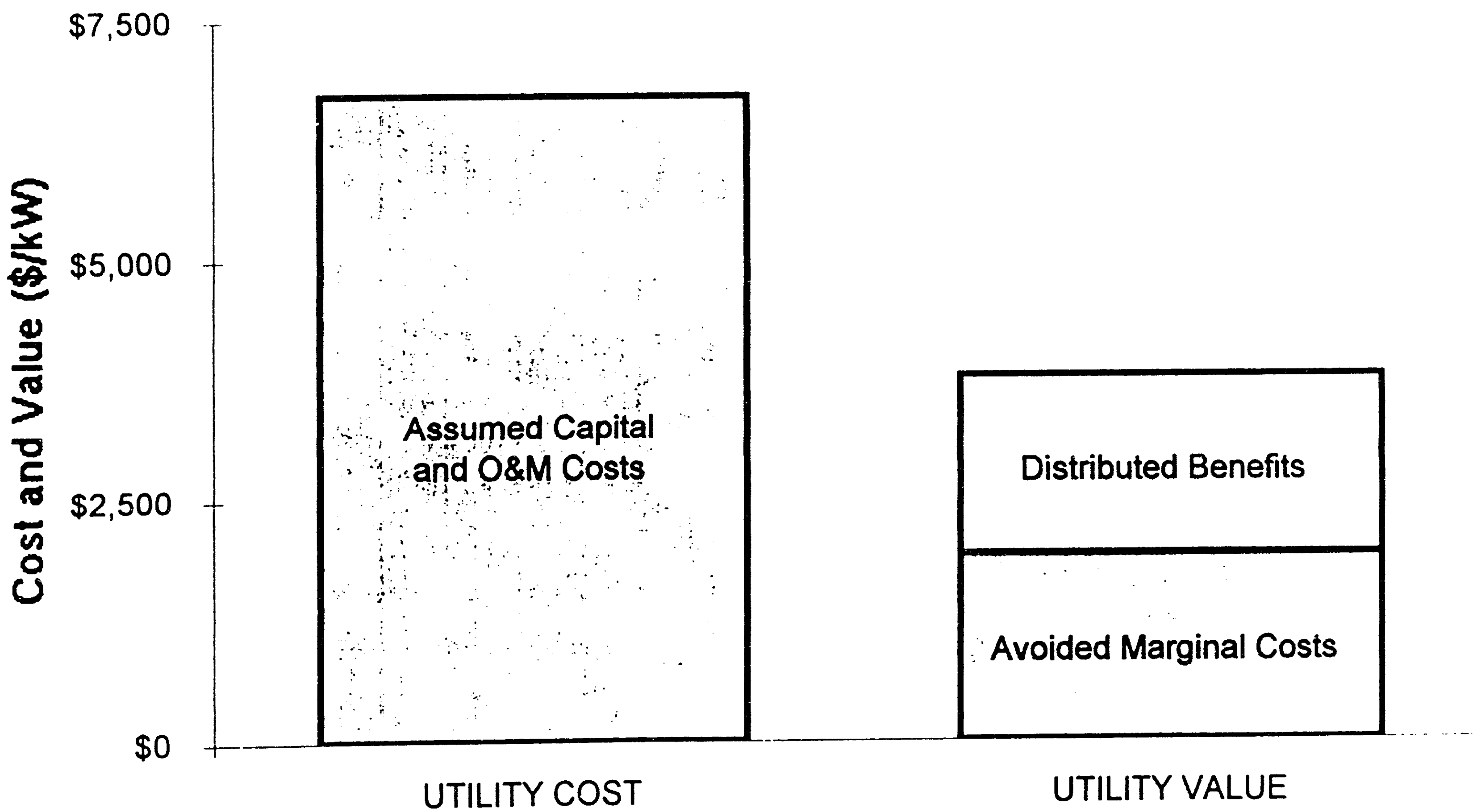
Policy Considerations

- Tax Issues
  - Credits
  - Treatment of Capital vs Expense Dollars
  - Ownership
- Environmental Regulation

Capital Dollars Cost Utilities More Than Expense Dollars



Economics: Utility Ownership



Note: $6,500/kW capitial cost is optimistic assumption

magnitude of these two bars is not important, it's going to be the comparison in this slide versus the next slide.

If you look at the cost of the photovoltaic plant to the utility, you can see that even with distributed benefits it exceeds its value, that is, it's not in the utility's economic interest to install photovoltaics.

Now, change the situation slightly, and say, instead of the utility owning these photovoltaic plants, you have the utility give selected customers in areas of high distributed costs a rebate or some other financial incentive to install photovoltaics and let them own the system. And, you can see the result of this in the next slide, and I apologize for your handouts, those two squares that turned out totally black should read "utility bill savings" and "lost revenues."

If you look from the utility's perspective, no longer is the cost to the utility the PV plant, the costs to the utility are lost revenues and the rebate cost, and if you compare the utility cost to the utility value, you can see that the value now is higher than the cost, so it can be cost effective for the utility.

If you turn to the customer's perspectives, you compare the capital cost, which is the customer's cost, to the value, and the customer's value includes utility bill savings, net tax savings and a rebate, and this idea is somewhat similar to what a utility would do with a demand-side management program, where they give customers incentives to put in these things.

Now, rather than focusing on this concept, I want to make a point with this graph. How do you take such a situation from not cost effective to a potentially cost-effective situation? It's due to the fact that customers, non-utilities, are treated differently from a tax perspective than utilities.

Certainly, customers, commercial customers in California, can get solar tax credits, utilities can't. Commercial customers are able to treat photovoltaic systems with very rapid depreciation schedules, which means a higher net present value to them, whereas, utilities cannot treat it in the same way.

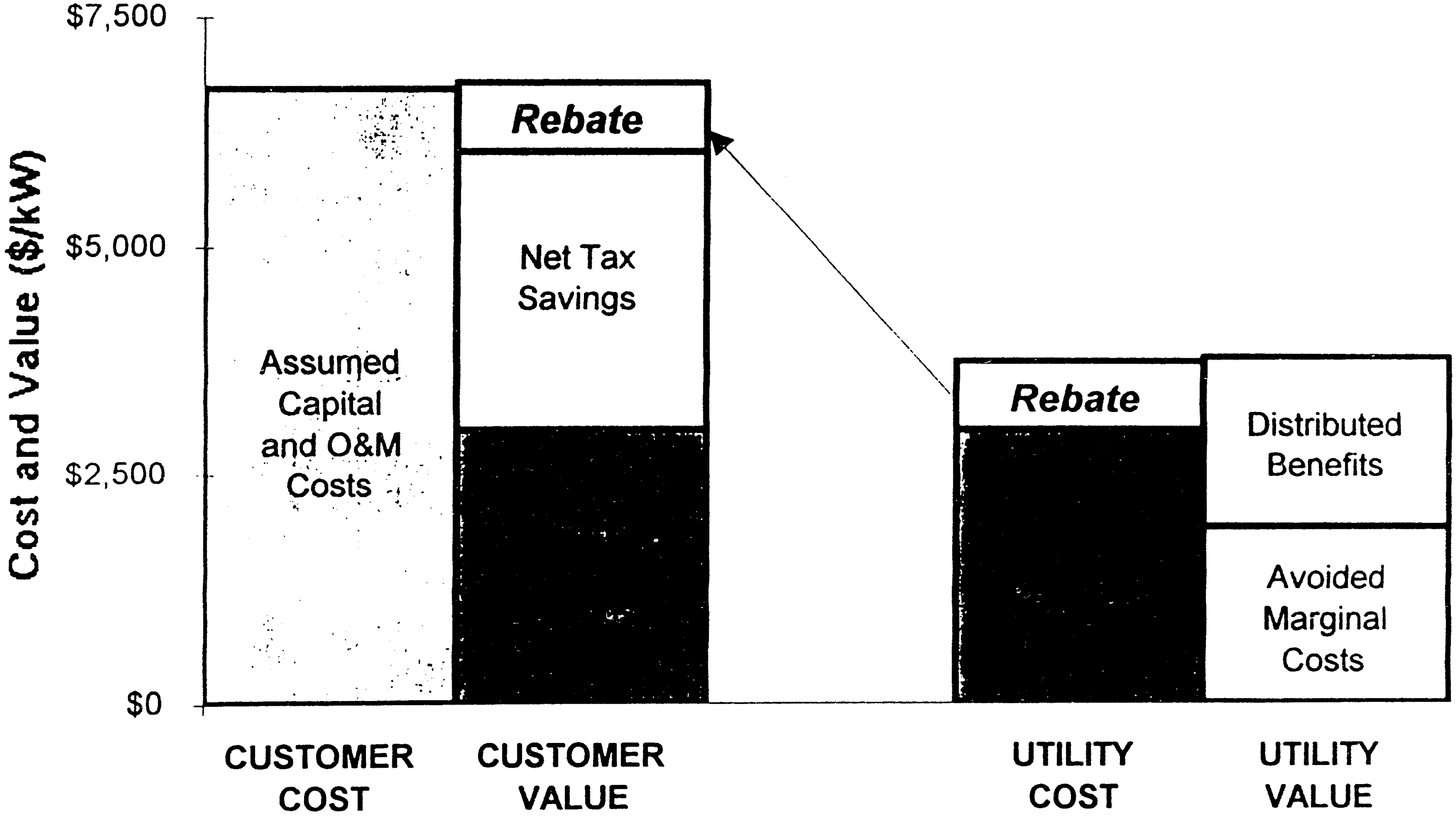
And, the point I wanted to make with this chart is, to whom the policy is directed may be important to include in NEMS because of these type of situations.

The other area of policy considerations is straightforward. Everybody is thinking about it, but I just wanted to mention it, it's the area of environmental regulation. Obviously, the inclusion of environmental costs in the cost of providing electric service could have very large impacts, and, in fact, a recent rate case submittal by PG&E showed that the environmental adder cost was half as much as the marginal energy cost.

Now, this was an environmental adder cost, which means the utility did not have to internalize this cost. This did not become a direct cost.

However, if policies were changed and regulations were changed, that could become a direct cost to the utility and become something that the utility would have to pay, and there

Economics: Non-utility Ownership



Note: This graph includes several optimistic assumptions

Environmental Regulation

- The inclusion of environmental costs in the cost of providing electric service could have large impacts

- A recent rate case submittal by PG&E showed the environmental adder cost to be half as much as the marginal energy cost needs to be some way to deal with that within NEMS.

In conclusion, first of all, PV can operate like a peaking plant for some utilities. That is, it has a good match to the system load, it's naturally dispatching for the right utilities, and that should be reflected within NEMS.

Second of all, properly sited PV can provide significant distributed benefits, and this is particularly important because this could greatly increase the value of PV. This area still is a big question mark, there's a lot of work being done with distributed utility concepts, and how much is the distributed utility worth, so people are still looking at the area and firm conclusions are not set, but it is concluded that there is value there, it's just how big is that number.

And, finally, tax and other policy decisions may have substantial effects on the PV market penetration.

MR. SITZER: Thank you very much, Tom. I appreciate those comments, both on PV, and also on the policy implications that you've discussed.

What I'd like to do right now is to make a couple of comments on what I've heard from reviewers, some of them I had heard before and some of them I hadn't, and, perhaps, give some people here an opportunity to discuss them who have worked on various aspects of this model.

Let me start out with some of the points that Walter made, in terms of hydropower. One of those is that we need to accommodate hydropower to the load duration curve segments that we're going to develop for NEMS, and we will be doing that. When we wrote the hydropower document, we hadn't yet come up with this methodology of different parts of the load duration curve, in terms of accommodating intermittent renewables and accommodating other kinds of electricity generation sources, and we will be looking at how to accommodate hydropower to that methodology, and that will be a part of the dispatch of hydropower.

Run-of-river hydro, again, because of its significance, we didn't include it, and I think, perhaps, we should look at that in terms of enhancements to the NEMS hydropower submodule.

You mentioned, Walter, the aggregation of geothermal sites to the 44 that are appearing in our model, and I think in any such large-scale model as NEMS there will be a certain amount of aggregation, and what we want to do is to make sure that it doesn't distort the results.

This particular one, I'm probably not the best person to comment on. I wonder if there's anyone here who would care to. Bill, would you have any comments on that aggregation procedure, or if you'd like to wait until another time, I can understand it.

Bill O'Neill is with Meridian Corporation, and he has been one of the developers of the geothermal submodule. So, I thought maybe he could make a comment on that.

MR. O'NEILL: My name is Bill O'Neill from Meridian Corporation.

This may be something we need more information on, but it's my understanding, from

Conclusions

- PV can operate like a peaking plant for some utilities
- Properly sited PV can provide significant distributed benefits
- Tax and other policy decisions may have substantial effects on PV market penetration

the information we have from Susan Petty, that the specific data that we really are dealing with tend to be more specific sites.

Her study included a wide variety of additional areas, particularly, areas of much lower potential, which we did aggregate, but I don't believe that we are using that data here. This may be something we need more information on to clarify it.

I did notice a discrepancy between the 58 sites, I believe, that were in Susan's study, and the 42 you had on your's -- 44, so maybe that's part of what you are talking to.

MR. SITZER: I think what we've done is to exclude very low potential sites at this point, in favor of those where some exploration has gone on, and where there is a higher probability of development in the future. So, that's one of the compromises that we needed to make, in terms of geothermal.

You talked about the need for additional pollutants, and I think that's well taken. The six that we've initially decided to track in NEMS, we've had a number of comments, we should be tracking such other items as particulates, H_2S and so on, and we will have the capability of tracking H_2S given the factors that are involved. I don't know if we'll be publishing them, but we'll probably make them available to people who are interested.

Moving to ethanol, you talked about the need for separate supply curves for different dedicated energy crops, and I take it that that's probably an important thing that we need to look at.

Dedicated energy crops are not going to appear in Version 1 of NEMS, at least at this point. We will be adding them in future versions, and when we do we will look very seriously at your suggestion.

I have found that the ARIMS model seems to be a bit more cumbersome than I had hoped it would be, in terms of estimating feedstock supply curves, and I hope to be tapping some other expertise on that, and I'll probably be coming to some of the folks in the Office of Conservation and Renewables to help me on it.

You mentioned no feedback to ARIMS, that's true. I guess it was our view that once we had established a range of costs from ARIMS, that we wouldn't need to go back to it for feedstock calculations. ARIMS, itself, is too slow to be included in NEMS. Hopefully, the range of costs that we're going to be developing from the ARIMS model will provide us with enough variability that feedback won't be that important.

You mentioned that market shares between supply regions and demand regions for ethanol fuel should be endogenous, and I tend to agree with that. The analogy I would make here would be with the coal market module, with which I'm also familiar, in which we try to do a least-cost representation oı coal distribution from its supply sources to its demand points.

Something similar could certainly be developed for alcohol fuels. At this point, the market share of alcohol fuels in the transportation sector didn't seem to me to warrant it, but it's certainly something we can look at, especially if we can do it on a simplified basis.

In wood, again, you mentioned separate supply curves for dedicated energy crops, and I agree that that's something that we need to look at when we add dedicated energy crops to the model.

Tom, there are three points I wanted to mention from what you said. One is that distributed benefits should be included in the NEMS competition for PV, and I guess it's my view that we are going to do that as an add on.

Walter, did you have any comments about the proposed methodology for that, since you all have worked on it?

MR. SHORT: I think we agree 100 percent with Tom, that the distributed benefits are certainly where PV is going to come into the market first.

I think Tom will agree with me that the data just doesn't exist right now. We do intend to have a place holder for simply an exogenous estimate at first, and there are some ongoing studies, collaborative work between DOE, through NREL, and others at DOE, and PG&E, and EPRI, that, essentially, is a distributed evaluation study.

And, we hope to get some input from that within the next year, and, hopefully, that will feed into more endogenous treatment of it.

Right now, about the only thing you can do is put in an estimate.

MR. SITZER: The tax implications of different technologies was mentioned, and I think the point about capital-intensive renewables versus fuel-based traditional sources of energy is important.

There will be tax implications considered in the model, whether it's in the electricity market model, or the renewable fuels model, I'm not quite sure yet. It may be that it needs to be in the electricity model, so that there's consistency of the tax treatment across all electricity generation sources, but that's something that we do need to include.

In terms of environmental impacts, we are both tracking and also trying to include ways of costing the environmental impacts of all energy sources. In terms of electricity, we'll be meeting the impacts of the Clean Air Act, in terms of its cap on sulphur dioxide emissions in a least-cost way, and since renewables will be a part of the menu that utilities and non-utilities have available to them, in terms of electricity generation, we hope to be able to model it in this way.

The apparent advantage that renewables have in terms of the environment should be included by their having something of an advantage in terms of capacity planning and dispatching.

So, those are the main points I wanted to make, and we've gone an hour and a half with three speakers, and I'll be glad to take any questions, comments or corrections that you all have.

Yes, sir?

(Inaudible audience question.)

MR. SITZER: The Department of Energy's Biomass Program, you say?

(Inaudible audience question.)

MR. SITZER: We will be looking at their data. The contractors that I have working on our wood submodule also work with the Department of Energy's Office of Conservation and Renewables' Biomass Division, and, again, most of the data that they have told us about has been coming from the U.S. Forest Service, but if there is additional data from the Biomass Power Division, I'll definitely want to look at it.

Yes? Could you identify yourself, please?

MR. BERNOW: Steve Bernow, Tellus Institute.

A couple of questions -- could you please define the QF benefit in your bar graph?

MR. HOFF: First of all, there are two benefits: should they be included, but just in terms of definition, QF benefits are when the utility has made contracted purchases with QFs as a result of reducing their energy expenditures, they reduced the contract values they have to pay to the QFs.

MR. BERNOW: Okay. That's what I thought it was -- and one issue that arises from that, again, is whether it's appropriate to include that as a benefit.

MR. HOFF: I would agree, and my purpose of showing all those benefits were, there's a lot of value, potential value, some of the benefits are questionable.

MR. BERNOW: I have one other question, your definition of --

MR. HOFF: When you calculate capacity value, the specific technical way we did it was, we used Garver's Load Carrying Capability Characteristics, and what that means, it's, in essence, an exponential function that looks at the whole year, but the only hours that contribute to that capacity value are probably the top 100, 150, depending on how steep the load shape is. So, it's certainly not an average value, it is a load carrying capability value, which is significantly different.

MR. SITZER: Any other questions or comments?

Yes, sir. Please identify yourself.

MR. MOLBURG: John Molburg, Argonne Labs. Is anybody prepared to discuss the performance models that you intend to use -- has it gotten that far?

MR. SITZER: I don't think we've really gotten that far yet. We're still designing -- those are still in the design stage.

In terms of data, Walter, maybe you could discuss some of what the background information that we are going to be tapping for that is?

MR. SHORT: We have started, John, on both those, actually, we are working on the PV one, and the solar thermal we actually did on a draft component design report, at least some chapters of it.

We have a subcontract out to PERI, I don't know if Tom Schweizer is here or not, but they are working on that aspect of it.

The technology characterization data will come, by and large, from an ongoing effort at CE right now, to do a standard set of technology characterizations, really, across the board of all renewable and conservation technologies, at least all the key ones initially.

On the PV side, it's, at least as far as the renewable fuels module goes, it's a fairly straightforward exercise, in the sense that you are just trying to characterize them, there's not a supply curve consideration per se, because it's a fairly abundant resource.

The main factors that are going into the renewable fuels module again is, really, how does the technology expect -- how do we expect it to change over time, in terms of its characterization, what periods of time, season, weekly, hourly, do we expect PV to contribute in, and how to match that up with the fairly general disaggregation of the load duration curve that the electric market module has in it.

And, I guess that's the two -- well, how the resource varies across the country, of course, but that's a fairly straightforward effort, the data exist for PV and for solar thermal.

What I said for PV, actually, applies also to solar thermal as well, by and large.

Does that answer your question? We'll have a draft out for -- I can't really answer that, as to when it's going to be available, but at that time you can take a look and give us a call.

MR. SITZER: Yes. I'm hoping to have that report out by -- I'd say by the end of February, hopefully, sooner than that.

Yes, let me just make one more point about technology improvement. It's very important in renewables and all the electricity arena that technology improvement be modeled on a consistent basis. It's difficult to look at each technology separately and then throw them all into the pot and see which one comes out ahead.

The Electricity Market Module is developing an algorithm that will look at them on a consistent basis, looking at learning curve effects in terms of, if you get additional production of solar thermal, or biomass, or whatever, what are the expected improvements in technology costs, and what further improvements in market penetration can be expected.

Our job with the renewable fuels module will be to at least get a good baseline of other than technology costs, and I will be working with CE on that as best I can, but I know it's been a controversial area for a long time, and I doubt that we're going to solve everything in version one of NEMS.

Yes, sir? Please speak into the mike.

MR. BERNOW: Steve Bernow, Tellus Institute again. I have two questions.

The first is, does the model provide places for characterizing different emission control technologies, plus control characteristics --

MR. SITZER: We'll probably be looking at a simple prototype technology. We are not going to be looking at separate technologies for MSW, as far as I know.

MR. BERNOW: I notice you have in your paper copy explicitly a source reduction factor.

MR. SITZER: Right.

MR. BERNOW: So, you need some kind of lever in there for recycling.

MR. SITZER: Well, the lever will be, what are the shares? I mean, what share of the total waste stream can we expect to go to energy, what share to landfill and so on and so forth. There is an explicit handle, and then how we forecast that out will be an off-line analysis of what's going on. If people want to look at a high recycle scenario, we can do it.

MR. BERNOW: And, to the degree that cogeneration is an important element, have you worked

MR. SITZER: Right, there is a confusing mapping issue there, but cogeneration for self use is going to be considered to be industrial demand.

So, the plan there is to have that on the Census division basis.

In NEMS, the demand models are working in Census divisions, and so is the integration of NEMS by Census division, plus California broken out separately. Electricity is by NERC region. To the extent that there is electricity generation for use by the grid, the forecasts are to be by NERC region; to the extent that there's cogeneration for self use, they are to be by the industrial sector and by Census division, and that's what we are going to try to keep straight.

It doesn't fall between the cracks, we are going to have to split it, we are going to have to split it up.

Do we have any other questions?

Well, thank you all very much for coming.

INTERNATIONAL OIL PANEL

February 1, 1993 - 3:15 pm

PANELISTS:

Mark E. Rodekohr, Moderator
G. Daniel Butler, Presenter
Ed Rothschild, Reviewer
Philip K. Verleger, Jr., Reviewer
David T. Smith, Reviewer

AUDIENCE PARTICIPANTS:

Martin Tallett
Ned Dearborn
Paul Leiby
Dan Santini

EIA

PROCEEDINGS

MR. RODEKOHR: I think it's about time to get started. I'll introduce myself. I am Mark Rodekohr, Director of the Energy Demand and Integration Division. I'll be the moderator of today's session.

The EIA presenter is Dan Butler, the team leader of the international modeling and forecasting team, who will give an overview of our model.

We're very fortunate to have three well known reviewers, with quite different backgrounds, in today's session. First, instead of David Montgomery, who appears on your program, we have Ed Rothschild, who is the Energy Policy Director of Citizen Action in Washington and has on a few, but very few, occasions been critical of DOE's policies. I know that it is hard to imagine that anybody could be critical of DOE.

He's to be followed by Philip Verleger, who's a visiting fellow at the Institute for International Economics and perhaps more well-known for his consulting work around town. I have to report that Phil also has occasionally been somewhat critical of our policies, but I'm sure that won't stop him from giving a good review.

And last is Mr. David Smith, who is the manager of supply coordination in the Planning Department of Marketing and Refining Division of Mobil Oil. I'm sure that Dave at least hasn't been publicly critical of the Department. He's probably been silently critical of the Department.

So the format will be that Dan will give an overview of the model, and we will follow with the reviewers in order. I would hope that you could keep your questions until all the presentations have been made, and when you do have questions, please use the microphone and identify yourself since the proceedings are being recorded.

With that, we'll start with G. Daniel Butler.

MR. BUTLER: Thank you, Mark.

I'm pleased to be here this afternoon to share with you our plans for implementing an international oil component within the National Energy Modeling System.

The domestic midterm energy forecasting systems used by the Energy Information Administration over the years have never had an endogenous international component. The world oil price has always been determined exogenously and used as an input to the domestic forecast. In fact, the world oil price has actually been the only so-called international variable used within the domestic forecasting methodology.

In order for the NEMS to be able to address international issues and their interaction with U.S. markets, an international energy module is being incorporated into the NEMS. Today's focus will be on the international oil component of the international energy module.

There are four oil components to the international energy module. The first is the world

International Oil
in the
National Energy Modeling System

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G. Daniel Butler
Energy Information Administration

EIA

February 1, 1993

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Components of the International Energy Module

- World Oil Market
- Crude Oil Supply
- Refined Product Supply
- Oxygenates Supply

oil market component. Basically this looks at worldwide petroleum supply and demand at a seven-region aggregated level and projects world oil prices over the forecast period.

The second component is the crude oil supply component. This forecasts import availability over time of various qualities of crude oils.

The third component is the refined product supply component. This forecasts the import availability over time of various types of refined products.

And last is the oxygenates supply component. This looks at the increased requirements for oxygenate blending in the production of gasoline and forecasts the import availability over time of methanol and MTBE.

Let's address each of these components in a little bit more detail. First, the world oil market. The world oil price forecasting mechanism used in this component is an old, tried and true Energy Information Administration war horse that has been used for forecasting world oil prices for over a dozen years. I'm sure many of you have heard of or are familiar with what we call the Oil Market Simulation model.

The important assumptions in this model are, one, that oil is the marginal energy fuel; two, the Organization of Petroleum Exporting Countries, OPEC, is the marginal supplier of oil; and, three, OPEC is assumed to set prices based on some sort of behavior that attempts to maintain OPEC production capacity utilization near a certain target level.

This third assumption is by far the most controversial one. There are those that argue that we should use a more clearly defined objective for OPEC, such as profit maximization. There are those that argue that there is really nothing wrong with the world oil price being an exogenous input to the NEMS.

We strongly feel that the OMS approach to forecasting world oil prices yields the best overall consistency to the NEMS petroleum methodology. Debate of this point alone could probably encompass this entire session, but I'll leave it now and merely say that I'll be happy to talk to anyone later about the pros and cons of the OPEC target capacity utilization method.

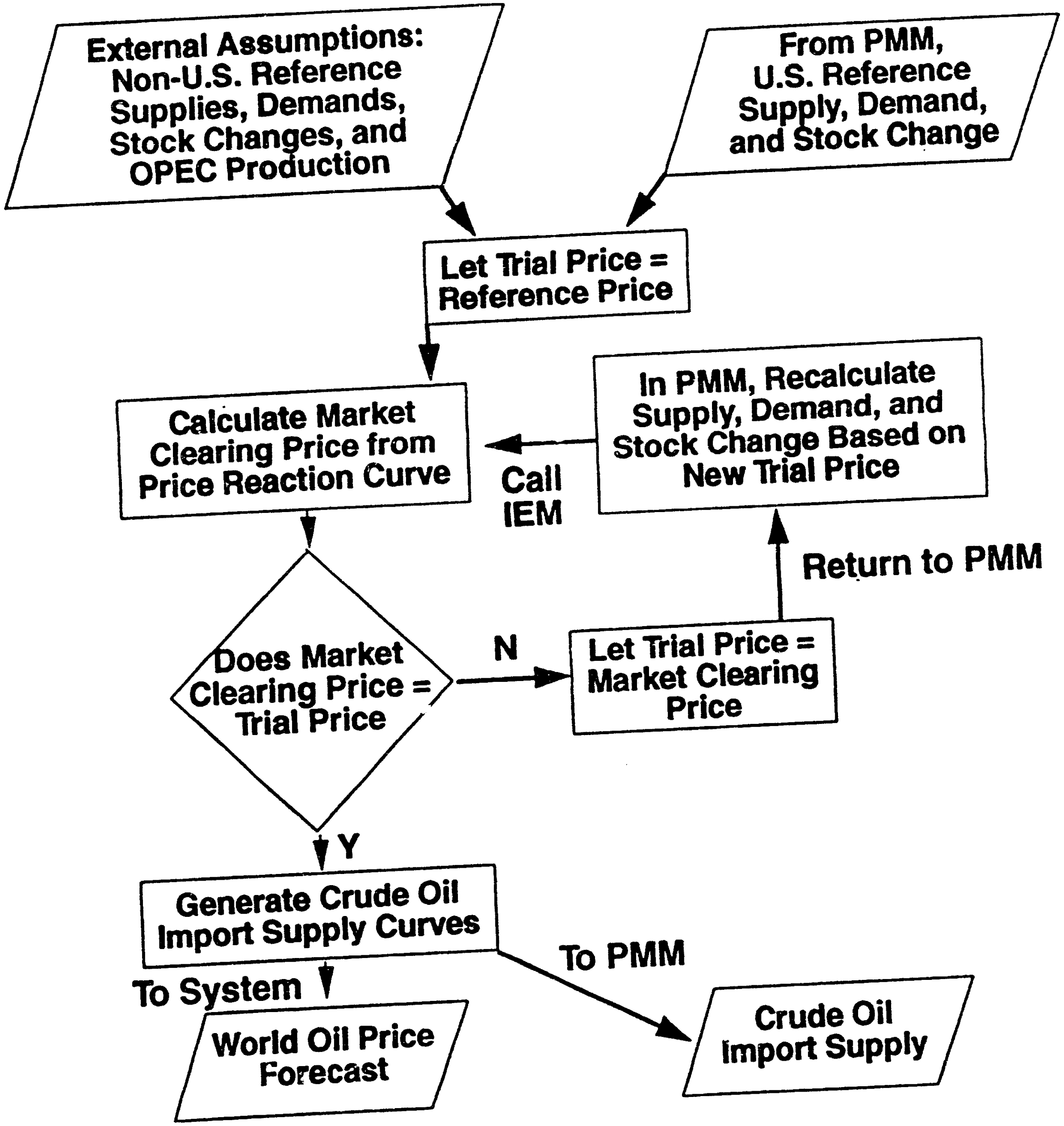
Note the first bullet in this slide before we turn to the next slide. It says that we're going to use an expanded version of the OMS model. What's been expanded?

The most important thing to recognize is that the NEMS is now the U.S. in the Oil Market Simulation model. The world will now react to the U.S. petroleum market, and the U.S. petroleum market, in turn, will be influenced by the world oil market.

What's referred to as the PMM in the chart is the Petroleum Market Module of the NEMS. It's the module that focuses on petroleum refining and other oil market considerations within the domestic NEMS environment.

This is a real important juncture as far as EIA modeling is concerned. We no longer have a two-number U.S. liquids supply and demand within the OMS model. It's the entire

Flow Chart for World Oil Market Component



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Oxygenates Supply

- Import supply curves provided for methanol and methyl tertiary butyl ether (MTBE)
- Supply curves constructed from data on costs, production capacity, and estimated natural gas prices
- Costs for new capacity construction reflected in the upper end of the supply curves
- Iterations between the IEM and the Petroleum Market Module determine the qualities, types, and sources of oxygenates
- Other oxygenates supplied from domestic sources

OIAF 1/93

NEMS system and its interaction with the rest of the world that's now in the OMS model.

Let's look now at the crude oil supply component. The international oil component will provide import supply curves for five qualities of crude oil to the NEMS at the Petroleum Administration for Defense District, better known as PADD, level of disaggregation.

The crude oil qualities will vary in quality from light, low sulphur crude, such as North Sea crudes, to the very heavy, high sulphur crudes, such as some of the Venezuelan crude oils.

In addition, crude oil quality will vary over time based on an off-line analysis of world crude oils at the field level. The ability to assess mid- to long-term crude oil quality is a capability that the EIA will be adding to their forecasting repertoire this year due to the procurement of a worldwide field level database with comprehensive exploration and production forecasting capabilities.

We have been working with a test copy of this database for a few months now and are especially impressed with its completeness. It even includes Communist areas and former Communist areas in its database.

The actual derivation of the import supply curves will be accomplished again, off line, using a detailed, worldwide refining and transportation model. This model is another recent acquisition by the EIA. It is a large linear programming formulation that reflects current and pending environmental regulations and contains structure that assesses potential expansion or retirement of domestic or foreign refinery capacity.

I think it's important for me to put in a word right now about such models. To adequately reflect the complexity of a refinery environment, such as the Gulf Coast of the United States, as well as stay updated on changes in refined product specifications due to environmental legislation, such linear programming formulations tend to be quite large.

When you link a dozen or so of these formulations together into a worldwide petroleum market, the model tends to be enormous. Five years ago such a model was virtually unsolvable in any palatable amount of time. However, new solution algorithms that have evolved over the last few years allow these models to be solved several times a day on one's desktop personal computer.

The last bullet on the chart merely alludes to the fact that the quality composition of the imported crude oils will be consistent with the forecasted world oil price.

We're now going to look at the refined product supply component. When this chart was originally produced, as the top bullet says, the international oil component was to provide import supply curves to the NEMS for five types of refined products. This has evolved into ten instead of five based on requirements from the Petroleum Market Module.

Let's talk about what we would eventually like for this component. Initially, we needed something quick but sensible just to put in the model as a place-holder until we were able to evolve our own methodology using our detailed worldwide refining and transportation model.

Crude Oil Supply

- Import supply curves provided for five qualities of crude oil

- Supply curves derived offline using a detailed worldwide refinery and transportation model

- Combination of imported crude oils choosen so the average refiners' acquisition cost is equal to the world oil price

Refined Products Supply Component

- Import supply curves for five refined product types

- Supply curves initially based on a current National Petroleum Council study

- Refined product supply curves adjusted to reflect changes in the world oil price

- IEM iterates with the Petroleum Market Module to determine a least-cost mix of domestic and foreign refined products

Luckily the National Petroleum Council was in the midst of a refinery study and had wrestled with many of the issues facing the NEMS in developing import supply curves for refined products.

We conveniently borrowed a set of these preliminary supply curves to get us started. The National Petroleum Council supply curves will be replaced eventually by our own set of curves in the near future. This, of course, is no reflection on the analytical rigor behind the NPC curves, but merely reflects a methodology that we are able to thoroughly understand ourselves, defend, and modify should the need arise.

However, there is a recognized shortcoming to any supply curves. It is very difficult, for instance, to get a handle on issues such as refined product exports and capacity expansion without actually having non-U.S. competing refining centers in the NEMS as well as non-U.S. product demands. What is really preferred is some sort of reduced form refinery formulation for each key foreign area, such as the Middle East, the Caribbean area, and Europe.

Such compact formulations are currently being developed for the U.S. at the PADD level. The only thing that precludes us from automatically adding such foreign refinery formulations to the NEMS is the concern over whether we're asking NEMS to do too much.

Domestic versus foreign refinery competition within the NEMS just might add a layer of complexity that would escalate run times unacceptably. So the jury is still out on whether we'll be able to add compact foreign refinery models within NEMS or whether we'll have to settle for import supply curves

The last component of part of NEMS is oxygenates supply. The Clean Air Act of 1990 imposed environmental regulations that require an increase in the oxygen content of gasoline. Domestic production is unlikely to be sufficient to meet the growing demand for oxygenates.

Therefore, the NEMS needs import supply curves provided for methanol and MTBE. This has been a growing concern for many analyses, and there have been a lot of studies that have surfaced in the last couple of years dealing with the global MTBE situation.

We have merely made use of the information and forecasts in those studies to put together the supply curves for methanol and MTBE.

Except for methanol and MTBE, all other oxygenates within the NEMS are assumed to be supplied domestically. Supplies will be adequate, and they will not be imported.

Very early in the game in hypothesizing what an international energy module of the NEMS might look like, we identified several areas which we called modeling challenges, and some of these we actually feel like we've made some progress on, while other ones are still up for grabs.

When addressing the first two as a whole, conventional oil's gradual decline as the world's marginal fuel and worldwide interfuel substitution due to price competition and the

World Oil Market

- Expanded version of the Oil Market Simulation Model

- Oil assumed to be the marginal fuel; OPEC the marginal supplier

- World Oil Price is a function of OPEC capacity utilization

MODELING CHALLENGES

- Conventional oil's gradual decline as the world's marginal fuel
- Worldwide interfuel substitution due to price competition and the market penetration of new technologies
- Gradual worldwide decline in crude quality
- Effects of environmental legislation on domestic versus foreign refinery competition and construction
- The cost of downstream refining operations required to produce reformulated gasoline
- Refined product supply curves produced using a model of foreign petroleum refining and transportation

market penetration of new technologies, we're still in trouble there. The only world market in the NEMS right now is the portrayal of the oil market. There is no worldwide natural gas market, coal market, etc.

The modules within the NEMS that deal specifically with natural gas and specifically with coal and electricity and such do make a forecast as to whether the U.S. will be a net importer of, say, natural gas or a net exporter of coal, and they have quantities associated with those numbers.

But within the NEMS per se, there is no worldwide market to really adequately address those first two bullets.

As I mentioned, we are obtaining this system that we feel will do a very good job of forecasting how crude oil quality will decline in the future. Likewise, the detailed refinery model that we have obtained will do an excellent job on the next two bullets, the effect of environmental legislation on domestic versus foreign refinery competition and also the cost of downstream refining operations to produce reformulated gasoline.

And the last bullet we feel like we definitely have a grip on. We can produce refined product supply curves based on our detailed refinery model.

Now, when you sort through all that's been said, what have we accomplished in the international oil component of the NEMS that we didn't have before? The first one is obvious. Within the context of a domestic forecast, we are going to forecast the world oil price. That means there is feedback between world oil markets and domestic oil markets.

The next two bullets talk about quantities and qualities of crude oil and refined products that are imported into the United States. The decision of how much and what type of import will be based on the economics of worldwide refining and transportation.

This is a real major accomplishment as far as I'm concerned. Heretofore in domestic forecasts, there has been an assumption of how much refinery capacity was available in the United States in a given year. The assumption was that you fully used that refinery capacity, and then whatever demand was left over was imported. This new methodology will actually determine the crude oil/refined product split in imports, and will be able to address the competition as the last bullet alludes to, between builds in domestic refinery capacity versus builds in foreign refinery capacity.

I think these are major pluses in the EIA modeling methodoligies that just have not existed before.

I look forward to hearing the reviewers' comments and observations on this proposed international energy module.

MR. RODEKOHR: Thank you, Dan. That was a good presentation.

We'll go in the order of the names as they appear on the program, and that means we'll

Enhancements Over Previous Models

- Forecast of the world oil price is endogenous

- Quantities and qualities of crude oils imported depends on the worldwide availability of crudes for trade and the economics of worldwide refining and transportation

- Quantities and types of refined products imported depends on the location and economics of available worldwide refining capacity and transportation

- Decisions on the expansion of domestic and/or foreign refining capacity are endogenous

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be hearing from Ed Rothschild from Citizen Action next.

MR. ROTHSCHILD: Thank you, Mark.

Whenever I see discussions of models, I always stand in awe because of their complexity, and I always am amazed to see how they end up working, and the question is: can we make them work well since they are models of the world, not actually the world?

And that gets me to my first point. If you look at the past and question, as I have, when prices are endogenously determined, are we going to see price changes over time that are smooth or not? As we know from history, and if you look back at all of the projections that have been made about world oil prices, the projections always tend to follow a smooth curve, but prices don't do that in any kind of sense.

We've had price crises, either prices going up substantially or coming down substantially, that affect the way people make energy decisions, whether they're production decisions or consumption decisions or policy decisions in Washington for whom this information is very, very crucial. And looking out at the world and seeing smooth curves, I think, is not as helpful as one would like, if you're going to engage in this kind of modeling effort.

So, the second point is, and as we have seen historically, politics as much as economics determine prices. If there were really a very competitive market, we'd have oil prices at $6 to $10 a barrel, depending upon all the low cost producers in the market producing at capacity.

So the question is: how do we then go about modeling political decision-making on something that's inherently an economic issue? I'm not sure I have the answer, but somehow you have to account for the fact that oil prices have a very strong political component to them and have an effect on the marketplace.

Now, we have an agency (or several of them, whether it's the Central Intelligence Agency or the Defense Intelligence Agency) in the federal government that tries to assess political changes. Obviously, one of them, for example -- you may not have heard this. I don't know if anybody has heard it. Has anybody heard the news today that King Fahd has been overthrown and the oil market is up to $40 a barrel? Did you hear that?

It's not true, but it highlights the point that if, in fact, King Fahd were overthrown by a fundamentalist faction in Saudi Arabia, the world would be thrown into turmoil. We have to have some political assessment because oil prices are both the function of economics and politics. So I leave that to the modelers to figure out.

MR. RODEKOHR: We'll talk about that.

MR. ROTHSCHILD: And that's the third. The third point here, which is that price should not necessarily be assumed to solely be a function of OPEC capacity because that assumes that OPEC has some kind of control over the world oil market or some kind of influence, albeit strong influence over the oil market. I think more and more that only some countries that are in OPEC have some influence, and those are the countries that have excess

Suggestions

- Model should not be used simply to project prices
- Model should be used to analyze impact of price changes on U.S. economy, energy sectors, investments, etc.
- Model should be used to gain understanding of interactions under different scenarios

World Oil Market
A Contrary View

- Prices do not change smoothly
  The WORLD is not smooth; it is lumpy.

- Politics as much as economics determine prices

- Price should not be assumed to be a function of OPEC capacity utilization, rather of "big events"

Model Requirements

- Persian Gulf Producers, not OPEC, have significant influence on world oil market
- Oil producing capacity information is highly uncertain
- Model's price projections must have some practical value
- Model should be used to analyze market behavior in response to price disruptions

production capacity, and that's primarily the Persian Gulf countries.

So, OPEC, as a determining factor, is not very crucial, if it ever has been, and there's plenty of debate about that. We won't get into that, but I think the key component has to be in the Persian Gulf.

And that's particularly the case with respect to the events in 1986 when the Saudis decided, for a variety of reasons, to increase their oil production, and prices fell from $29 a barrel in December of 1985 to a low of $9 a barrel in July of 1986. Now, that was not projected by anyone who was looking out over time as to what would happen in the price of the oil market, and as a result we had enormous economic dislocations, and I think, again, if a model is going to be useful, we have to come to grips with some of these types of events, big events, that happen and change the nature of the oil market.

The other thing I want to raise concerns about, and I think this is very key, is that if we're going to have a model that does use capacity, oil producing capacity, and OPEC as such an important criterion, we really have to know what that capacity is, and the fact is we don't. And, as the Persian Gulf crisis demonstrated, the Saudis were able to produce a lot more oil than many people assumed they could produce.

I don't think the information we have about production and capacity in countries where it's a state secret like Saudi Arabia is very good. Now, there may be some people that know about that; some of the ex-ARAMCO partners may have some inkling about that. The Central Intelligence may have some inkling about what the real production capacity is, but this information is difficult to find, not everyplace, and you really have to get a good handle on that before you use it, it seems to me, as the basis for making these projections.

Again, in terms of the price projections, my view is -- and looking at this as just a user of the information -- projections have to have some practical value, particularly for policy. What I'm proposing is -- and I'm sure this is going to be the case -- when we use models, we use them to try to see what the alternative policies are.

You run through -- we were talking about this in the beginning -- changes in energy taxes and see what the different results are. It seems to me that all too often policy-makers need to be made aware of the limitations of models -- that models are not simply projections of a one-time nature; that they're really there as a practical tool to be used to analyze various policy options.

I think some of that tends to get lost when we raise these issues.

The question here, and I'm glad this was one of the questions that the modeling challenges, is why do we assume that oil will decline as a marginal fuel and that there will be greater penetration of coal and nuclear power, which is the way this assumption is expressed in the design report.

From what I can tell, and I don't know, again, what type of agreement there is, it's going to be a long time before oil, which is a very versatile fuel, I think, will be displaced and will

Questions

- Why assume oil will decline as marginal fuel and that there will be greater penetration of coal and nuclear power

- What data is being used for OPEC capacity and capacity utilization and with what degree of confidence, especially in light of experience during Persian Gulf Crisis

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- Does "expansion" of refining capacity also mean "upgrading"

- What is the basis of high confidence in NPC analysis of Clean Air Act Amendments given errors in cost estimates

- In view of difficulty in projecting short-term prices, why should we have confidence in long-term price forecasting assume a marginal position, particularly with coal and nuclear having so many environmental problems.

If anything, natural gas may become a substitute before coal and nuclear power become substitutes, I'd like to see some effort made to address questions about two issues: one, the degree to which oil is likely to become a marginal fuel in the near term, 20 or 30 year horizon, or the degree to which natural gas could be the fuel that replaces it.

And secondly, whether the data being used for OPEC capacity and capacity utilization are reliable and accurate. I think we need much more and much better information on that.

Another question that arises in looking at the design report, there's the use of the word "expansion" of refining capacity. The question I have: does that mean upgrading? Expansion means, as far as I understand it, increasing the utilization capacity; whereas upgrading means taking a quantity of heavy oil and making more lighter products.

I don't know. Am I correct you're using that interchangeably?

MR. BUTLER: It could be both.

MR. ROTHSCHILD: It could be both, yes.

The next question I have is what is the basis of the high confidence in the National Petroleum Council analysis of the Clean Air Act Amendments, given the enormous errors in their cost estimates.

Well, it's referred to in here, and it's not referred to with a lot of question marks around it. So I don't know what the confidence level was, but there's no way of telling that, but we've seen that the NPC numbers, I think, were highly overinflated and particularly given the benefit of reality to reexamine that.

The last one, I think, is one I've alluded to. In view of the difficulty of even projecting short-term prices, I didn't see EIA, for example, project the $3 per barrel price decrease that has occurred from October through December of 1992. There was no projection of any kind of decrease. So that's in the short-term horizon.

Now, it's just like a weatherman. Weatherpeople have difficulty, even with all of their complex models, projecting tomorrow's weather in Washington, D.C. with any high degree of confidence. We don't have very good confidence levels in projecting energy prices with a high degree of confidence three months hence, let alone 20 years hence, with this kind of model.

So the question is: what kind of confidence? Once all this is done and everything is incorporated and all of the criticisms that are raised and all of the refinements are made, after all that's said and done, what kind of confidence are we going to have in the long-term forecasting with respect to the value it's supposed to have, which is to premise policy and other decisions on the information?

So the first point has already been made. This model should not be used simply to project prices. Obviously it's going to be used as a factor in the overall model, but we have to be very, very careful that this is not, quote, unquote, projecting where prices will be. It's not. It's just giving some kind of estimate of where prices could be given certain conditions.

And I think language happens to be very, very important because reporters tend to look at a report, and they say, "EIA says that prices 20 years down the road are going to be anywhere between $20 and $60 a barrel." That's not what these things are for.

In my view, again, I want to repeat this. This model should be used to analyze the impact of price changes on the U.S. economy, energy sectors and investments. Clearly that's what we're building all of this for, to help us assess what impacts are going to occur, because, as consumers, we want to know that, if we're going to have an increase in the gasoline tax of 50 cents a gallon, what that will mean, not just for the economy, but also for the various sectors of the economy and for regions of the country, rural, urban, etc. That is the kind of information we find highly useful, and it is my hope that this model will serve or help serve that function.

And the same thing, if we project different scenarios, again, it is my hope that this model will be used to understand the interactions as opposed to being used in a kind of fixed fashion to project what the future will be.

Thank you.

MR. RODEKOHR: Thank you, Ed.

I will reserve a little bit of time after everybody's done with their comments for a few rejoinders. I should have announced this at the beginning.

So with that I'd like to have Philip Verleger come and give his view of the world.

MR. VERLEGER: Thank you, Mark.

It's a pleasure to be here. I think the record should say that my criticism has been reserved for DOE policy, not EIA.

MR. RODEKOHR: I said DOE.

MR. VERLEGER: Actually it's a real pleasure to be here. I've watched this energy modeling effort, participated a little in it since 1975, and this review of NEMS is certainly the most open, the most original, and the most thoughtful, and so I compliment you.

I would also caution that we ought to remember as economists and analysts that we've really done a good job when we get the sign of the change right.

MR. VERLEGER: Right now we know that certain people in Washington are trying to think about energy taxes, and we're really getting a view of what happens when policy gets made without staff, and I'm quite concerned because, you know, they're going to come up with three-digit, four-digit accuracy, and I remember working at one point on a piece of legislation that will remain nameless that was supposed to raise $263 billion by 1990, was it, or 1987? I think it raised 11.

So this is a big problem, and we have to be humble.

Today what I'd like to do is ask two basic, fundamental questions of DOE. First, why do you ignore the market in projecting the world oil price? And I'll come back and explain what I mean.

Second question is: why do we still adhere, not just at DOE, not just in EIA, but throughout the world oil market community, to the antiquated view that producer cartels can do anything more than perhaps push prices up artificially for a few months?

And I guess a third point -- no, I'll ask a third question -- whether one can really model product prices in an annual model, which as I understand this is, given the proliferation of products, the reduction in the storage capacity, and the commodity market behavior that we observe in these markets, the great volatility of commodity prices, which is going to get larger.

Now, I will say that after having spent my time in the government and at a consulting firm building models for DOE, I served penance at Drexel Burnham in the Commodity Division. I think for the last ten years I've really been focusing on commodity markets. So I come at this from a very different view.

In the commodity market, long term is a month, but let me start with the -- and that's a month forecast -- with the fundamental question: why ignore the market?

DOE and everybody else goes through these elaborate efforts to project long-term oil prices. Some of us got critical of them in the early 1980s and said prices might be able to go down, and, Ed's right, nobody got $10 right. But today, in the last 10 years, there's been a development of a large number of financial instruments that can and are being used by consumers, by producing companies, by producing countries to protect themselves both in the short and long term.

These are futures, forward sales, oil index financing, royalty trusts, swaps. This information is available on a real time basis from the New York Stock Exchange on an instrument called the BP Royalty Trust, from various publications such as <u>The Petroleum Economist</u> on swaps, and they are continually giving off a projection of the future oil price, three, five, seven years out, trade is flat or down. That is, there's no assumption about real prices going up. People are willing to put money on the line, much larger sums even than the ones put into this modeling effort, millions of dollars on the basis that prices are not going to rise.

Review of commodity market theory, and I guess Turnofski's "Econometrica" paper in the mid-1980s, suggests -- the best citations suggest that futures prices are biased upwards predictors of future price levels if either consumers, buyers or hedgers, speculators or hedgers are risk averse. So this says that when one looks at the market, a fairly liquid market where my calculations now say there's several billion dollars at risk, the expectation should be that prices are going down, and we don't get this out of models.

This expectation is further confirmed by the work of some other economists, particularly the people at the Fed. who have looked at one of these instruments, the BP Royalty Trust, and it suggests that when one backs out of it a price expectation you also get falling prices. The BP Royalty Trust, by the way, is an instrument that trades on the New York Stock Exchange. BP has sold 16 percent of the first 90,000 barrels per day of its crude oil pay production to this trust and then buys it back on a daily basis, and the price is tied to the price of WTI with really no uncertainties in terms of cost. There is a cost schedule in it, but the cost schedule is fixed.

If you treat this as an options pricing instrument, you get a projection of nominal prices probably falling at three or four percent per year.

So I think, and I ask this very humbly: why is it we get one answer, when one builds a model, of continually rising prices, and when people put large sums of money on the table, one gets an entirely different answer?

And if you're giving advice to a Senator or Congressman or a president of a company, which piece of advice do you tell him to take?

Second question, why do we adhere to the view -- and I call it antiquated view -- that cartels work? We have had in the DOE model for years this producer reaction curve built out of the Kyle/Gately model, and it made a lot of sense, and certainly I've made a lot more use of it than I should, and I think all of us have.

But if one goes back and looks at cartel theory, and really the best initial work was in the '40's by John Meynard Keynes on looking at the fluctuations of commodity prices and the proclivity of consumers not to buy when prices are falling and to buy when prices are rising, and then follows this through, you find that restrictive commodity agreements, which are agreements between producing countries to hold production down to support prices, generally don't work for very long, and they particularly don't work when there's a proliferation of producers, as we've seen in oil.

And one of the problems we have now is we've taken the Soviet Union and broken it into a number of separate producers, which raises the number of producers and puts further downward pressures on prices.

I am just completing a study, and one of the things I've looked at is the correlation between the ability to sustain higher prices and what are called Herfendahl indices, that is, the concentration of markets. As you look across markets which have been attempted to be cartelized or in which restrictive commodity agreements have operated, you find that you need a Herfendahl index of around 3,000, which is highly concentrated, to sustain higher prices above cost.

Oil was about 2,500 in 1980. It's about 700 today. So as one looks, I think one's got to look at this concentration in the market, and that leads you to ask the question: well, really shouldn't one look at capacity, as Ed said, and assume that the capacity is going to be fully utilized or pretty fully utilized unless the U.N. or somebody steps in and shuts some capacity down?

Now, another way to ask this question is: are producers maximizing profits? And Ed raised the question, "Gee, King Fahd has been overthrown." That would clearly cause Saudi Arabia to cut production for a little while, but not for long, and one explanation you can give for Saudi Arabia's behavior over the last several years is that they're out to maximize income.

If they can get other countries to cut production and they cut production, too, they raise their income, but if they have to be the only ones, their income goes down. The residual price elasticity facing Saudi Arabia is greater than one, and it's going to increase.

So that fundamentally I think the second way of asking this question is to look at this issue of how likely is the organization to be able to find a group cut in production that can be sustained. History from a lot of commodities says it's not long, and then you come back and you say: prices will go lower, sort of confirming what the financial markets and what those people putting funds at stake seem to be saying.

Third question. I applaud your attempts to build larger linear programming models in the petroleum products market, but I think we're finding there's a second fundamental problem. As you know from the Clean Air Act, we now have a proliferation of products. There are 18 grades of gasoline. They've basically got to be segregated in storage.

Storage is shrinking in the United States. Storage is shrinking worldwide, and as you segregate the market to smaller and smaller segments, you wind up getting larger and larger fluctuations in prices.

This gets to a behavior of commodity markets that's described by Brian Wright and Jeff Williams, who are economists at Berkeley and Stanford. They talk about the likely volatility of prices. What most people who have examined commodity markets in detail found -- and I admit to being not one of the statisticians or econometricians -- but John Cuttington at Georgetown and others -- that commodity prices generally are random walks without drift. That is, they're flat, with one exception. You can lend to the future, but you can't borrow.

And what this means if you have a stock out, you run out of inventories, you get very large increases in prices, and that's to answer Ed's question about the potential increases in prices. One of the problems is if you disrupt supply and you have low inventories, then you get a large increase in price that's temporary.

Wright and Williams explained this as a demand curve for a commodity that's highly price inelastic down to some prices level, say, P*, and then becomes very elastic because a producer can transfer the commodity from this period to the next, and then they draw this rule of thumb out that you can lend to the future, i.e., store, and so that when prices get low enough, you store until the next period, but you can't borrow.

What this says is as we fragment the market or segregate the market into more and more products, we reduce the storage availability, and so we raise that level at which that discontinuity occurs, and we increase the likelihood of more and more discontinuities.

So while I applaud the effort to model the various product prices, I don't think it's going to work because I think you're going to find one type or another type of product not available for a month or two, and that is going to contaminate the annual data, and it's going to be a steadily worsening problem, and I feel sorry for EIA because every time one of these points of inflection is reached, a whole lot of Congressmen are going to call up and say, "Who do we blame this time?"

You know, and people like Ed or maybe even myself and these nonprofits are going to get called up to the Hill and say, "Can you explain it and help us blame the oil companies?"

Lastly then let me comment on MTBE. As my bio says, I am on the board of directors of Valero, which is a small oil company and pipeline company that happens to own a refinery down in Corpus Christi. It's a unique refinery in that it turns residual fuel oil into unleaded gasoline and state-of-the-art.

When I joined that board, they had just put to us a decision to build a world scale MTBE plant. I think it's 14 million tons, $225 million. I voted yes. The new guy always votes yes.

And you had the standard projections of the tightness in the MTBE market. Little flags keep going off in the back of your mind. I've been here before, and so we came into this this fall. Everybody was saying MTBE was going to be tight.

Well, what a commodity economist looks for in a tight market is very high spot prices because that's indicating tightness and anticipated tightness, and that wasn't happening, and what we've seen is a quick construction of capacity to make MTBE. Petroleum refining engineers being what they are, they have found ways to milk MTBE out of all of these plants, and so I come back and I look at these projections of shortages in the modeling effort, and I come back and say, "No, we've been here before, and we'll be here again."

Now, Valero fortunately has an advantage in terms of the cost of its feedstock to this thing, which makes it profitable, but there are a whole lot of companies that keep going through this and keep making the same mistake.

So I would spend less effort on MTBE probably than you have.

Well, lastly, let me conclude with just two cautions. During the last election, we kept hearing about tests. "It's the economy, stupid," the model that the Clinton campaign had and the model that the Bush administration should have followed.

There's another anachronism that's been around a much longer time, and that's KISS, Proctor & Gamble's "keep it simple, stupid." And I worry that this thing is becoming so complicated and so difficult to understand that it's going to be quite difficult to -- even though you know how to make it work -- turn out the timely answers that are needed to deal with some of these problems.

And as I come back, I started by saying we do a real good job when we get the sign of the change right, and I think that one should try to emphasize that more, particularly with the Hill and with the people that are pushing for all of this detail.

Thank you.

MR. RODEKOHR: Thanks very much, Phil. I know it's going to sound hard to believe, but timeliness is a project goal. So I'll say more about it later.

And now I'd like to have David Smith from Mobil Oil.

MR. SMITH: Thanks for the opportunity to offer some comments on the NEMS model. I am going to focus my remarks this afternoon on the refined products portion of the International Energy Module (IEM).

For the last year I have been working on a subcommittee of the National Petroleum Council Refining Study, involving foreign refining models, which appears to parallel EIA's efforts on the International Energy Module. In fact, I understand the EIA at one point was considering using output from this NPC foreign modeling work in the early phases of the IEM. I thought it might be helpful, therefore, to share with you some of the experiences encountered by our NPC group in modeling the foreign refining regions.

I'll highlight first the assumptions and the sources of some of the assumptions; the basic methodology used in the regional refinery models; how it was tied in with the logistics model of U.S. domestic and foreign supply options; and some of the problems we encountered along the way which might have some parallels in the IEM.

Then I'm going to turn to the International Energy Model being proposed as part of NEMS and discuss some of the challenges you may encounter in your own modeling efforts. Finally, I'll close with some suggestions on how you might address at least some of those challenges.

Basically the purpose of the NPC study, initiated at the request of the Secretary of the Department of Energy a couple years ago, was first, to assess the industry ability to provide clean products and meet other emission control mandates of the 1990 Clean Air Act and the resultant competitiveness of the U.S. refineries versus offshore supply; and, secondly, to advise on the oxygenate supply adequacy for the U.S., which Phil has just commented on.

For the NPC study, refining facilities were modeled for each of the six foreign regions, with each region modeled as a single refinery. The six regions were Canada, Northwest Europe, the Mediterranean (including North Africa), the Middle East, Latin America, and the Pac Rim. No attempt was made to model the CPEs, former CPEs, or Africa, south of the Sahara.

For the assumptions, wherever possible and practical, we tried to use information in the public domain, or third party resources; but supplemented when necessary by judgement of the various NPC study groups as an override when it was felt appropriate to do so.

International Energy Module (IEM) Review

NPC Foreign Refining Model Experience

- Assumptions
- Regional Model Methodology
- World Logistics Model
- Problems

IEM Proposed Model

- Challenges
- Suggestions

NPC Experience - Assumptions

Regional Representation (Single Refinery)

- Modeled - CAN, NWE, MED, M/E, L/A, P/R
- Not Modeled - CPE's, Some Africa

Assumptions (1995 / 2000 / 2010)

- Pricing - 1989 Actual
- Crude Quality - Constant Base, Incr. AL
- Prod. Quality - Industry Survey
- Prod. Demands - EIA Projections, Outside Studies
- Limited Product Grades

New Facilities

- 1995 - "Firm" Projects Only
- 2000, 2010 - Optional Further Facilities
- Costing - Estimates for W/S Units, % Offsites, Location
- Offline Estimates of Environment / Health / Safety (EHS) Costs

Three forward periods were examined: 1995, 2000, and 2010, although it was felt looking at 2010 was really a stretch.

For pricing, we basically went back to using 1989 annual average published prices, escalated to 1990 dollars, as a constant through all study years. Consistent with this approach all facility investments, operating costs, etc. were examined in terms of 1990 dollars throughout the study.

Base pool crude quality for each region was kept constant throughout all years, with the swing crude in each region assumed to be Arab light, reflecting the Middle East as the likely incremental crude producer in the world.

For product quality, we relied for the most part on an NPC industry survey that was sent out to regulatory agencies, other governments, international oil companies, foreign national oil companies, etc. This was aggregated by a consultant for confidentiality reasons, and provided back to the NPC as ranges or averages, along with an indication of the number of respondents involved in the aggregation.

For product demands, we looked at three scenarios and used EIA projections as a starting point. The high growth cases in the NPC foreign studies was assumed to be the same as the EIA intermediate growth case in their studies. (Other foreign demand scenarios were permutations off of the high case.) This was supplemented, where possible, with available outside study projections. Given the size of the models, we also dealt with a limited number of averaged product grades.

For new facilities in the 1995 model, we only assumed those investments in place that were judged to be firm. This assessment was provided by a consultant who essentially applied their assessment of probability to projects that were announced as either under or close to construction.

For the years 2000 and 2010, the model offered the option of further facilities being added at a cost that included a return on the new facility investment.

Investment and operating costs estimates for new facilities were provided by contractor consultants based on U.S. Gulf Coast construction of world scale size process units, along with NPC/consultant estimates of add-on percentages for off-sites and start-up costs and location factors for constructing these same facilities in each of the modeled regions.

Off-line we spent considerable time and effort trying to estimate the stationary environmental emissions costs for the foreign regions. Admittedly, this turned out to be a very difficult exercise, and one that was highly subjective in terms of costing.

The methodology used in the regional models consisted of fixing MJD (i.e. motor gasoline, jet and distillate volume) for each of our three reference case demand scenarios. Crude, heavy fuel oil, and LPG were allowed to vary, with other byproducts (e.g. lubes, asphalts) fixed. The model was tuned against 1989 actual data and verified against 1987 actual data.

NPC Experience - Regional Model Methodology

- Fixed MJD Demands for Ref. Case
- Crude, HFO, LPG Variable. Other Byproducts Fixed.
- Models Tuned vs. 1989 Actuals
- MJD Incr. Cost/Vol. for Exports to U.S.:
  - Delta vs. Ref. Cases
  - Ranged MJD Volumes/Mix
  - Annualized Cost of New Facilities
  - Input to World Logistics Model
- Spreadsheet Summary for Analyzing LP Runs
- Inter-Regional Product Flows
  - 1989 Vol. Flows - Start Point for Future Years
  - Checked Imp/Exp Drives with Assumed Flows

In tuning the model, limits were imposed as to how much the crude in each region could vary from the estimated actuals for 1989. We also imposed tolerance limits as to how much the fuel oil could vary off our estimates and how close a weight balance would need to be achieved, before accepting the regional models as representative.

Once the reference cases were established, cost/supply curves for potential product exports to the U.S. were developed as deltas off the reference cases. The volumes were ranged, as were the mix percentages between gasoline, jet and distillage within these ranges. Where appropriate (year 2000 and 2010) new capacity was permitted to be added if it was economic vis-a-vis annualized (ROI) costs for the associated investment. The resultant cost/supply curve data was then provided as input to a separate logistics model, which I will touch on a bit more in the next slide.

In analyzing the output from the foreign regional model runs, we developed a spreadsheet summary of what were felt to be some key parameters. Typical of a lot of studies, as the timetable for completion draws near, "crunch time" occurs. Thus, we had a tremendous amount of data to deal with in a short period of time. As a result, we set up a spreadsheet of critical factors that could be summarized, examined and compared between runs to judge the efficacy of the regional model outputs.

Establishing future interregional product flows (between foreign regions) posed another challenge. We assumed 1989 volume flows as the starting point for all future years. Then, off-line, import-export drives were checked with these assumed flows in the model, by taking shadow prices from the LP runs and adding freight and duties. With the off-line guidance, macro adjustments were made and the LP models rerun where necessary.

Let us turn now to the next slide and the logistics model. It is not really a "world model" as labeled on the slide. Rather, it is a U.S. regional supply model having both domestic (inter PADD) and foreign regional supply options. The purpose of the logistics model was to determine the U.S. product supply sources and cost for clean fuels under the assumptions provided. For input, the cost volume curves for the six foreign regions and six U.S. PADDs were utilized. (N.B. The U.S. West Coast PADD was broken apart into two separate PADDs - California and outside California.) This model had built in demands for each of the U.S. regions, and associated transport costs and import duties to get potential U.S. grade product from each foreign region or U.S. PADD refining location, to each of the U.S. demand areas.

This logistics model was also calibrated against the estimated 1989 actual prices, volumes, product movements. This was accomplished by deriving scaling (cost) factors necessary to make the model output match actual 1989 operations.

The model was then validated by running it, with the 1989 derived scaling factors built in, against 1987 actuals. This resulted in a close check of 1987 actual operations.

Oxygenate domestic and foreign supply options were built into the logistics model, but the associated supply-demand balance was handled off- line.

What are some of the problems we ran into? Well, one of them was trying to aggregate

NPC Experience - World Logistics Model

- Purpose - Project U.S. Product Supply Source/Cost
- Input
  - *MJD Cost/Vol Supply Curves for:*
    6 Foreign Regions, 6 U.S. PADDS
  - MJD Demands for Each PADD
  - MJD Transportation, Duties
- Calibration
  - Scaling Factors From Calibration vs. 1989 Actuals
  - Validated vs. 1987 Actuals (Same Scaling Factors)
- Oxygenate S/D - Handled Offline

NPC Experience - Problems

- Aggregating Heterogenous Regions (e.g. Pac Rim)
- Reliability/Interpretation of Survey Data
- LSFO Production, LS Crude Segregation
- Environmental Costing for Foreign Areas
- Consistency of Pricing Between Regions
- Incompatibility 1989 Pricing With Announced Facilities
- Seasonal/Operational Price and Volume Swings
- Calibration of Regional Models
- Selecting MJD Volume Range / Mix for Curves

heterogeneous regions, for example, the Pac Rim. The Pac Rim has a wide geography, ranging from the Indian subcontinent to Japan to Australia, with configurations ranging from topping to very sophisticated upgrading, along with a fairly wide disparity of product qualities.

Another problem was the reliability and interpretation of survey data, which served as the primary basis for future product quality assumptions. Effort was made to send out a carefully crafted questionnaire to solicit meaningful responses. However, the resulting aggregation of responses (necessary for confidentiality) to some extent masked the data and quality of the responses. In addition, we really didn't know what bias there may have been on the part of the respondents, or some respondents may have put in a lot more thought than others or had more extensive knowledge of the subject. Also, we were faced with converting ranges of the aggregated responses into averages that could be used in the LP models.

Low sulfur fuel oil production/demand also caused a problem. In the out-year models, as the percent of low sulfur fuel oil increased, there was difficulty in some regions in meeting projected low sulfur fuel oil demands. This required rerunning some of the models, and making provisions for segregating low sulfur crude to enable meeting the low sulfur fuel oil requirements.

As noted earlier, stationary environmental costing for the foreign region refineries posed a real challenge, in trying to determine what these costs might be and also how these stacked up relative to the U.S. To estimate this, we needed to assess where foreign regions stood vis-a-vis the U.S. in the 1989 base point year, and to what degree and at what pace foreign regions would "catch-up" with both prevailing and projected U.S. refinery environmental standards (U.S. refinery costing had some better definition from a comprehensive consultant study commissioned as part of the NPC study, a better knowledge base of the U.S. regulations, and input from an NPC survey of domestic refiners).

Consistency of pricing between regions. We used the best available 1989 published pricing data, but for some of the regions this was based on very thin markets and in some cases not published. Also, some of the pricing didn't always "hang together" between regions vis-a-vis logistics and known product flows. This made it necessary to create some "pseudo pricing," by assuming logistical parity with other key markets.

Incompatibility of 1989 product and price differentials with announced facilities. The 1989 pricing drives do not necessarily reflect the future supply-demand environment nor does it appear to support some projects being announced, e.g. resid conversion. For example, in the out years, with light product demand projected to grow faster than heavy fuel oil demand, the spread between the black and the white products could widen and provide increased drive to build more upgrading.

There were seasonal operational swings, along with volume swings because of volatility. Given the limitations of the LP, and the number of cases involved it was necessary to use annualized data. This drawback was minimized somewhat by using actual year 1989 data as a basing point in terms of both prices and associated product movements and focusing on the deltas between future year and 1989 year model runs. In effect, the NPC study assumes the difference between annual pricing and seasonal pricing in terms of driving the models will be the same for future years as it was in 1989.

Calibrating the regional models was not an easy task. The model was run against the 1989 actuals, where adjustments were sometimes made on severity, unit yields, cut points, etc. to match actual regional production volumes within targeted tolerances. However, in some cases these fixed 1989 operating parameters resulted in strained operation when applied to the out year model runs, where projected demand patterns and product qualities differed significantly from 1989. This required rerunning of some 1989 models to achieve reasonable consistency between 1989 and future year runs.

Selecting the volume range for the U.S. product cost/supply curves. As a starting point for future year references cases we assumed 1989 import volumes to the U.S. from each of the modeled foreign regions were the same as they were in 1989. We then developed supply/cost increments all the way from zero to twice the 1989 levels in an attempt to bracket potential future year product U.S. import levels. In some cases this turned out to be not enough, requiring that we go back and rerun the models over a wider volume range.

Against this background, what are the challenges for the NEMS International Energy Module? The bottom line is to end up with a model that is credible not only to users like yourselves, but also to your customers, such as other government departments, policy makers, the industry, public interest groups, etc. Recognizing also that some of these customers may be disbelievers who will challenge the results derived from your model output.

How about the applicability of the model to future years, when the product specs will be different; demand ratios are going to change; and prices may not look anything like today's? How applicable will the model be then?

How about analyzing and validating the runs and the results? If the conclusions emanating from the model run or study fits conventional wisdom, it tends to be more readily accepted. However, if it defies conventional wisdom or results in some surprises, you're going to have a much tougher selling job.

Who are you going to assign to do the model? During the early stages while it's being tested and validated there will probably be plenty of expertise available and savvy people scrutinizing it. What's going to happen after the model is up and running? Are the people who are running and maintaining it going to be knowledgeable and experienced in the industry? Will they have ever seen the inside of a refinery?

How about the assumptions? This may be one of the most important aspects of the model, e.g. projecting demand patterns, refinery capacities, prices, product qualities, unit yields, government policies, etc. I'm not sure a survey questionnaire is the best way to go about this, at least not the way it typically has been done. There's a lot of biases, and you just don't know how good the responses are or how much effort was put into providing insightful answers. The responses often involve ranges and/or are qualitative in nature which then have to be interpreted and reduced to single point data, presenting its own share of uncertainties.

Environmental costs in the foreign area. As noted earlier, this is very tough to estimate.

IEM Model - Challenges

- Calibrating, Maintaining Model
- Applicability of Model to Future Years
- Analyzing, Validating Runs and Results
- Establishing Key Assumptions
- Consistent Assumptions Between Modules
- Environmental Costing for Foreign Regions
- Assuring Model Transparency
- Recognizing "Hidden" Assumptions

What cost levels are significant? In the NPC study, this was one of the softest areas in terms of confidence and yet, at the same time turned out to be one of the most important in terms of the cost impact on competitiveness of U.S. refinery supply versus foreign refinery supply of U.S. clean fuels.

Assuring model transparency. NEMS' outline says this is going to be a very transparent model. I think that's an admirable goal, and all I can say is let's wait and see.

Be aware of hidden assumptions, which may be the flip side of the transparency question. These are items that might have strong influence on the results, but don't necessarily get much focus or attention except maybe by the analysts who build the model. It may include cut points, unit severities, process capacity, and utilization, the yield structure on each of the units. These are all elements often time buried in the model, yet which can significantly impact model output.

Now that I've listed a number of challenges, let's turn to some suggestions.

Assumptions. Instead of going out with multiple choice questionnaires saying, for example, "Here are five ranges of gasoline sulfur levels for each foreign region. Which ranges do you think are most likely to occur next year and five years from now?" I suggest that instead, EIA initially prepare a draft reflecting their best judgement of specific key assumptions drawing on their own expertise and informal dialogue with industry and agency contacts, etc. An experienced, knowledgeable consultant might even be commissioned to prepare such a draft. Then send the draft of these specifics to industry, foreign governments, agencies, etc. for their comments. I believe you will get a much more focused response if they have something specific to react to rather than just a general question or best guess of which range to check off. It tends to force a "yes I agree" or "no I don't" and "is my disagreement enough for me to suggest something specifically different?"

Prices. You've got to explore prices and price differentials up and down from current levels. History may or may not tell you what's going to happen about the future. So this really needs to be explored.

Regional modeling. At the very least, I would suggest splitting the Pac Rim into two or more homogeneous regions. That's something we didn't do in the NPC study; but in retrospect probably should have.

Also, build in some CPE import-export options and U.S. export options, if you are not already planning to do so.

Regarding model analysis. Spend some time creating a well-thought out spreadsheet summary that can be used for comparing model run output and results. Make sure you have experienced analysts reviewing the runs for reasonableness. You might even consider forming an expert oversight group, (e.g. industry, NPC, etc.) to review the assumptions and important model runs and results. I'm not talking just in the early stages when you're trying to test the model, but also use such an oversight group on an ongoing basis.

Model maintenance. The models need to be updated periodically. Set a regular

IEM Model - Suggestions

Assumptions

- EIA or Consultants Draft Assumptions
- Send to Industry, Agencies, etc. for Comments

Prices

- Explore Range of Future Prices/Differentials

Regional Modeling

- Split P/R Region Into Two or More Homogenous Entities
- Consider CPE Imp./Exp. Options in Regional Models
- Include Option for Exporting U.S. Products to Foreign Regions

IEM Model - Suggestions (Continued)

Model Analysis

- Use Well Thought-out Spreadsheet Summary to Compare Runs
- Assure Experienced Analysts Review Runs for Reasonableness
- Form Expert Oversight Group (e.g. Industry, NPC) to Review
  - Assumptions
  - Important Model Runs/Results

Model Maintenance

- Update Periodically
- Provide Continuity, Knowledgeable People on Model

Model Calibration

- Tune Annually With Latest Available Actuals
- Provide Auto Feedback of Future Yr. Actuals vs. Projected

schedule, (maybe once a year), and, consistent with career development plans, model maintenance should be made a priority in terms of providing knowledgeable personal and continuity.

Model calibration. The model just can't be tuned once, validated and then assumed to be representative forever. This model needs to be tuned and calibrated at least once a year using the latest available actuals you've got.

Then, as a report card, try to have some automatic feedback of your future year actuals versus what was projected the year or two before.

I have a couple of other suggestions, in addition to those noted in the slides. In terms of emphasis, put the most effort into the assumptions and the analysis. Maybe even do some preliminary screening early with rough numbers to try to find what is significant and what isn't. Spend less time on trying to fine tune uncertain numbers. It is in the nature of assumptions to be "uncertain" and trying to fine tune the assumptions is oftentimes not productive. Assumption uncertainties are better tested through sensitivity analysis.

Another point is overoptimization. This is inherent in our regional modeling efforts and I guess in most LPs. The area of optimization our NPC study group was most concerned with was the model's tendency to assume there was no logistical barrier to product interflows between units to maximize utilization of upgrading capacity. In reality, there may be costly logistics, a separate company operations involved that might preclude some of this. We tested as a sensitivity by looking at what would happen if capacity utilization in some critical units, e.g. FCC or hydrocracking, by 10-20% were reduced.

Before closing, I would like to add to something that was said here by the first two reviewers on this panel. I think it is very important on any study that you are undertaking with regard to the IEM model (or any other part of the NEMS system for that matter) that you carefully spell out, but "loud and clear," the critical assumptions that go with each of the conclusions and how the conclusions change if these assumptions are changed. As Ed mentioned, the newspaper picks up a conclusion -- maybe a base case tied to a critical assumption -- and runs with it. Worse yet is the chance that some people in legislative or policy making positions might fall into the same trap. Highlight the assumptions!

That concludes my comments. Thank you.

MR. RODEKOHR: Thank you very much, Dave.

MR. RODEKOHR: Those were all excellent reviews, and I want to start real soon with questions to both Dan and myself and the reviewers. I'd like to take just a couple of minutes for a little quick rejoinder, and maybe clarify a couple of things.

First of all, Ed, you're right. Prices are lumpy. We have not perhaps explained what we do with regard to some of the issues you brought up very well in our CDRs. We consider those events that cause very rapid price movements to be usually temporary in nature, and we have a completely different modeling system that we use to evaluate disruptions.

However, you are correct in your assertion that it's likely that you'll have some of these events in the future, and you need to look at the effect of variation in prices in more detail, and we're going to try to do that.

Also with regard to prices, I also think this is something we haven't done much of, but I think after we complete a policy analysis, we need to go back and we need to ask ourselves: okay. What if prices are different from what we assumed? Would that make any difference to the conclusions reached in this analysis? And I think that's an important piece of information to offer.

We did that in one study, our SPR sizing study, and found out in that situation it didn't seem to make much difference. Once you told people that, they became a lot more comfortable with the results because they knew that this big source of exogenous variation didn't matter much to the final results.

We're also guilty, I agree, of using the word "OPEC" too frequently without explaining what it means. In the context of what we do, it probably doesn't mean very much. What's important are the actions of four or five big Mid Eastern producers, and we do evaluate it that way. We just don't do a very good job of explaining it.

If we led you to believe that oil was going to trade off versus coal and nuclear, we shouldn't have because it really is gas. In our projections, oil remains the biggest source of energy to the world over the next 20 years, although its market share does decline a little bit, and it mainly loses it to gas, if my memory is correct.

The NPC figures that you said were overstated may be true, but they're not the NPC figures we used in this model. No way.

I guess, Phil, my only problem with the BP Royalty Trust, I do think it's a good source of information, but it is a thin market.

By the way, just to set the record straight, our price projections have real prices falling over time until, in the low price case, until around the year 2000, and they only get back up to $18 by 2010.

I agree with you the product prices are going to be a real bear. It's going to be interesting to see how that works out. I also agree with you about MTBE. We tend to be in the government and even parts of industry sort of taken with these new items, and I mean I hate to say anything against refiners or chemical producers, but there does seem to be a bias towards overbuilding that occurs every now and then, and so you're right about that.

And I very much like your suggestions, Dave. I think you have a lot of very practical suggestions, and on maintaining the continuity and quality of people, I'm going to use that to recommend that I get a 25 percent raise for next year.

But seriously, I thank you for all your comments, and we'll be happy to take questions to anybody at this point unless, Dan, do you want to say anything?

Okay. We'll get you a microphone.

MR. TALLETT: My name is Martin Tallett, and I'm speaking in part here as the co-developer and supplier of the international integrated world oil industry model that Dan Butler was referring to, and I'd just like to make one or two comments and observations of my own, including observations on the comments of the reviewers.

First of all, I think it's fair to say that we as analysts support a lot of the concerns that the reviewers have raised, and we're aware that when you use these kinds of models, you can run into difficulties with them doing things you don't understand, and that has to be controlled and contained; of overoptimizing, and so on. And we hope that with our work with DOE and EIA we've been able to convey some of these concerns to them.

Another point is that the question of short versus long-term simulation came up, and really based on our experience, which includes, for example, the Middle East crisis analyses through the year 2000 analyses, there's a very different mindset that's needed and a very different set of variables.

In the short term, typically in the petroleum industry, there's no option for investment, and you can get extreme situations arising. In the long term, the model is going to tend to react more stably. If crude supply quality changes in the world, the worldwide long-term situation is not going to change dramatically because the world will adapt based on the underlying process, technology and economics.

There's a difference in approach here, but one thing that this kind of model does, in either situation is it only models rational market behavior. Even in the short term it's effectively modeling an equilibrium point in time.

One of the associated concerns is that of data. In the long term and the short term, there are data problems. In the short term nobody has available demand data for what's happening this week when Saddam Hussein has just invaded Kuwait. Your data are generally several months old. So you're making assumptions, and over the long term there's the uncertainty over data, and I would agree with the comment that a lot of time has to be spent on assumptions. When we undertake studies, we spend most of our time, I would say, trying to come up with a base case that we feel is realistic and representative.

In terms of the problems that NPC appears to have incurred with their approach to tackling the international market and its interactions with the U.S., our own sense is that the integration into one model of all of the regions of the world is not the be all and end all, and shouldn't be the only tool that one uses, but it does do away with some of the interaction type problems that Mr. Smith referred to, and does enable you to study a range of different assumptions quite quickly, and this is a capability that now EIA has available to it.

MR. DEARBORN: My name is Ned Dearborn with EIA. I'm speaking as an individual analyst.

Phil Verleger made the point earlier: "Believe price projections that are consistent with where the smart money is." If you were to advise the President -- by implication, to offer him a binary choice: do you believe modelers or do you believe the futures market? -- I think it worth remembering both an historical and a behavioral point.

First, the historical point. The smart money, back in the early 1980s, badly miscalculated on oil industry investment. It badly miscalculated on synthetic fuel investment, billions of dollars. It badly miscalculated on the situation leading to the take-or-pay crisis, which is still with us.

In hindsight, many have said we should have paid more attention to the simple relationships of Economics 101 and believed them. In truth, if you go back to the EIA's annual fuel outlooks of 1980 and 1981, the international chapters had some very prescient price projections that we've long forgotten.

In addition, there was the more recent crisis with Iraq and the invasion of Kuwait. During the Iraq crisis, futures market prices went sky high. Some people would say this happened because of a bubble -- the crowd-driving behavior of panic. Such behavior may also have been coupled with the kinds of distortion that produce anti-decision-analysis choices -- for example, in insurance purchases and in lottery ticket buying.

In any event, in all these historical cases, the smart money would not have been providing good advice to the President.

The second thing I'd want the President to reflect on -- as he considers futures market price-path projections versus modeling price-path projections -- is the behavioral issue. To the degree that people in financial instruments markets are pure hedgers, they really don't care whether the price is wrong or not. They're just locking in a price for the future. The other people in financial instruments markets -- the smart money people -- are speculators. The one thing they all agree on is that the price which is being offered is wrong. They think it's wrong one way -- too high -- or they think it's wrong the other way -- too low -- but they think it's wrong.

The only people who think that the futures-market price is right are the rational-expectations economists, and they can make their case. But their argument shouldn't be confused with the smart money argument, which is in error. The smart money in the futures market thinks the futures market price is wrong. I'd invite a comment.

MR. VERLEGER: The last two comments have, I think, given me an opening. In the first place, it was stated that you don't know what's going on for seven or eight months. I think one other piece of advice I would suggest is you ought to incorporate one or two very good traders in your modeling effort for two or three months to learn what they know because the traders at Cargill in grain and in oil, the traders at Phebro, the traders at J. Aaron know very well what's going on, and they have very good information, and they have it momentarily, and almost all of it's reflected in price.

MR. DEARBORN: But aren't they betting against the price?

MR. VERLEGER: No, no. If I could speak, please, now the simple mistaken statement that you made, that many people make, is to look at the futures market as a single price. There is a long literature on distribution of prices, and one of the gravest mistakes that was made in 1990 was at a meeting of Michael Boskin, the President's Economic Policy Committee, trying to decide what to do. The Secretary of Energy was there discussing supply and demand, and Roger Porter, the President's advisor, pulled out the Wall Street Journal and said, "Well, oil for delivery next July is only $22." We don't need to do anything.

All of the DOE analysis was just thrown out the door. All your good work was thrown out the door basically because the Secretary of Treasury in the Bush administration hated futures markets, didn't like them, didn't understand them.

There is a great deal of information that can be derived from the futures market, and that has to do with whether prices are in backwardation or contango. For those not familiar with these two wonderful terms, backwardation is when spot prices are at a premium to forward prices. Contango is when spot prices are at a discount.

The long literature, very good literature on this, says that when inventories are tight, markets will be in backwardation. For example, if oil for spot delivery is selling for $40 today, and oil for delivery 12 months from now is selling for $20 a barrel, you would be an absolute fool to hold one extra barrel of inventory because the earning on that oil is a minus 200 percent or better.

On the other hand, when the market's in contango, selling spot at 12, forward at 20, you can earn a return, and traders, companies like Cargill, Shell, have played this game for years, building inventories and reducing them.

The symptom that was missed in 1990 because of what you refer to as speculators -- and, by the way, there are very few speculators in the oil market according to the statistics partially because these markets are manipulated by countries, just as the coffee producers once tried to manipulate prices. In July we had contango. The Kuwaitis had overproduced the market and pushed it into contango. In August, after the invasion, it suddenly went into backwardation, and we knew stocks hadn't changed. Indeed, everybody made speeches that the industry has gone into this crisis with high stocks. We don't have to do anything.

But as Lord Keynes wrote, as Wright and Williams and a number of other economists have written, there is a precautionary demand for inventories. Just as you suddenly want higher cash balances if your job should be eliminated and you decide you'll become more cautionary -- and as we're seeing today, every oil company decided they had to be more prudent with their stock management, so they held onto prompt stocks. That pushed the market into backwardation, and it was a key signal.

Now, to ignore these markets and to make -- you know, I was talking in 1980 about the potential of $10 oil. I don't recall the prescient forecasts of EIA. I know that they grew it less rapidly than the forecasts that went to $100, but to frankly ignore them is to give extraordinarily bad advice, and the companies that have ignored them are having troubles.

I would also say that if you go back and you look at the history of the overinvestment during that period of time, with some exceptions, it was money coming in for tax reasons. Remember in the early 1980s after we deregulated oil, until the Tax Reform Act of 1985, we had massive tax incentives, and so you could see all of these drilling funds.

If you peel that out, you had less. The second thing is there is a thing in economics called the bubble phenomenon. We've seen it in Japan. We've seen it in Texas. We've seen it in California, where investors get too excited by the present price.

The best example I can find of adjustment that we have seen in the late 20th Century is in Mexico where in 1990, in the fall, they looked at the high prices, $32, $33, and they listened to economists who said, you know, once this crisis is over, the prices could fall, and proceeded to engage in hedges which have essentially locked in prices for 1991.

The next benefit of this step was to increase the income of the Mexicans in 1991 by $1 billion relative to what it would have been had they done nothing.

The World Bank is going out now and working with producers to make use of these instruments, and I think -- you know, I'm not saying to throw out the forecasting, but I'm asking that the acid test ought to be what can you derive from these instruments.

MR. ROTHSCHILD: And there's one policy prescription here that Phil and I know well for the 1990 period, that if you used the indicators of the futures market to advise the President, what you would have said was, "Use the SPR," or announce that you're going to use the SPR because you want to take the speculation or the bidding up of the price out of the market. You simply say, "We're going to put oil back in, and nobody has to worry, and nobody has to worry about the supply availability, and it's going to be there," and that would have been a good test of the SPR, to see if it would have worked the way it is supposed to work, namely, to protect the U.S. economy by lowering expectations of increasing prices.

MR. RODEKOHR: More questions?

MR. LEIBY: Hello. I'm Paul Leiby of Oak Ridge National Laboratory.

I think a lot of what you're doing is a tremendous improvement, but I wonder whether it might be helpful to think about expanding the international module to incorporate gas as well as oil. You mentioned, of course, that as oil becomes less important at the margin because of substitution with gas, but I didn't hear you say how that is represented in your explicit modeling framework. Apparently it's not.

And what I read about, your foreign gas module appears to be focusing principally on Canada and a couple other nearby regions. I just would like to suggest that perhaps you would like to construct a database of gas wells quite similar to your oil wells and explicitly look at the supply of both competing fuels.

An interesting phenomenon you observe is that the marginal suppliers of gas and oil in the long term become the same countries largely, Middle Eastern countries and the former

Soviet Union, which suggests that if you're interested in analyzing market power, you'd like to consider the possibility of joint cartelization of oil and gas.

MR. RODEKOHR: What you say is certainly to some extent true, and maybe I gave you the wrong impression. We include gas in our analysis, but not in NEMS, and we can do that by the way we derive our oil supply figures. We have sort of a separate spreadsheet where we look at gas and try to back out what oil will be.

We're thinking about including it in NEMS, haven't figured out if we have enough resources to do it, but that's a good point about the possible gas cartelization because you're right. I mean the big gas suppliers are going to be in the Middle East. They're going to be in the former Soviet Union.

Now, there is some question in my own mind about how big of an oil producer the former Soviet Union is going to be because their reserve figures aren't very big for oil. They've got tremendous gas reserves, and they can clearly exert some power in Europe and perhaps some other regions, too. So it's certainly an issue we shouldn't totally brush aside. I agree.

MR. LEIBY: Just a last point. Of course, if you're interested in methanol --

MR. RODEKOHR: Right.

MR. LEIBY: -- the most likely sources are the Middle East.

MR. RODEKOHR: Absolutely. I mean I don't know why, when people were talking about using methanol as a gasoline additive, they thought it was going to make the U.S. more secure because it was pretty obvious to us you're going to get that methanol from the Middle East and other regions where it's very cheap. You're right.

Other questions?

MR. SANTINI: I'm Dan Santini from Argonne National Labs.

There are two people that I know of that predicted the oil price collapse in 1985 and 1986. I'm one of them and a guy named Dale Steffis that got written up in the Wall Street Journal.

Based on work that I've done, I have a few comments on the model and what it should do when it's done. In the first place, I don't think that the model should generate real prices of oil in any scenario that's published which would in the future go above 1981 levels.

Second, I think it should have long oscilations in oil price as an inherent characteristic, those oscilations being eliminatable only with great effort.

Another observation is that politics is important, but it's been my observation in looking at the history of the price movements that the political instability occurs when oil is worth fighting over, and it merely -- the political instability accelerates the price increase, but it's occurred in part because it's worth exploring for oil with military equipment.

There was an example brought up of the lack of wisdom of government. I don't know, but the example I like to bring up is just before the oil collapse, Exxon announced a plan to mine oil shale in Colorado and ship water from the Great Lakes out to Colorado. So I don't think the government has a lock on stupidity.

I personally think that the Department of Energy should justify its existence by showing that introduction of advanced technology can keep prices lower than they would otherwise be, and I regret that in the past EIA had projected increasing prices over, you know, a long period of time to very high levels.

I think that EIA should resist producing projections with high oil prices, as I mentioned, since what happens when they do that is the DOE project officers use them to justify uneconomic programs.

And with regard to methanol, it's not true that methanol is as likely to come from the Middle East as is crude oil, given the cost of transporting a Btu of methanol. It's much more likely to come from locations closer to the United States if you look at the facts.

MR. RODEKOHR: I didn't mean to say it was going to be a cost difference between crude oil and methanol. I just was pointing out the inputs to the methanol being natural gas are in huge supply, and they sell for next to nothing in the Middle East.

MR. SANTINI: That's certainly true, but the point at which the value is zero, given transportation costs is a lot closer to the United States than for crude oil.

MR. RODEKOHR: Yeah. There are cheap supplies of gas outside of the United States, too, sure, that are not in the Middle East. I'll grant you that.

MR. SANTINI: And we do benefit from competition in world energy markets, and if oil and natural gas compete, that will assure that even if we're stuck with importing oil, at least it'll be cheap oil.

MR. RODEKOHR: True, that's a good point.

We haven't projected prices to rise above 1981 levels in many years. Our projections keep going down year in and year out, and this last year they went down by $5 a barrel, and I think thanks to my ability to convince our managers that I finally am getting it right.

MR. SANTINI: Well, I didn't make any arguments about continually lowering the price, the projections that you made, although given the history, it's probably a good move.

MR. RODEKOHR: Other questions? Well, I'd really like to thank all of the panelists for giving us an excellent review, and I'd like to thank all of you for being attentive and, as well, giving us excellent questions.

Thank you very much.