BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Numbers

ELECTRICITY MARKET DESIGN AND STRUCTURE : RM01-12-000

(RTO COST BENEFIT ANALYSIS REPORT) : RT01-2-000

: RT01-10-000

: RT01-15-000

: ER02-323-000

: RT01-34-000

: RT01-35-000

: RT01-67-000

: RT01-74-000

: RT01-75-000

: RT01-77-000

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: RT01-99-000

: RT01-100-000

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: RT01-101-000

: EC01-146-000

: ER01-3000-000

: RT02-1-000

: EL02-9-000

: EC01-156-000

: ER01-3154-000

: EL01-80-000

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NORTHEAST REGION

REGIONAL TELECONFERENCE

FOR INDUSTRY AND PUBLIC

Hearing Room 11H-7

Federal Energy Regulatory

Commission

888 First Street, NE

Washington, D.C.

Tuesday, March 19, 2002

The above-entitled matter came on for teleconference, pursuant to notice, at 9:30 a.m.

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PROCEEDINGS

(10:00 a.m.)

MR. WHITMORE: Okay, this is Charlie Whitmore at the Federal Energy Regulatory Commission, and I will be hosting the call today.

I understand there are already close to 40 people on the line, so I think we probably better just get started.

Welcome to everybody. Thank you for joining us today. The purpose of the discussion is to clarify the cost/benefit analysis on RTO policy, to answer any questions that you have about that report in preparation for your comments on April 9th and the reply comments on April 23rd.

We are not going to have any presentation here at the beginning because the report is out and we would like to leave as much time as possible for questions and comments.

And all of the conferences, this is the fourth-- the third conference for the public and industry. We had four conferences with states last week. All of those conferences are being transcribed, and the transcripts will be available for free 10 days after they are done.

You can also pay Ace Reporters to get them ahead of that, if you need to.

Because they are being transcribed, I would like to ask each of you to identify yourselves before you talk.

I will also do a roll call at the beginning before we get started.

The transcripts of these calls will go into all of the public dockets that are related to RTOs. The transcripts from all the calls will go into all the dockets. So you will be able to use them wherever. And also into the Standard Market Design docket.

I think we are ready for intros now. Around the table here at FERC, let me start with:

MR. LONGENECKER: Bill Longenecker, staff.

MR. GOLDENBERG: Michael Goldenberg from the General Counsel's Office.

MR. RUSSO: Thomas Russo, FERC.

MR. WHITMORE: And I am Charlie Whitmore. I do strategic planning here at the Commission.

And joining us on the telephone today should be a representative or two from ICF. Jim Turnure, are you there?

MR. TURNURE: Yes, I am. This is Jim Turnure at ICF Consulting. I am also Project Manager for the Cost/Benefit (inaudible).

MR. RUSSO: Jim, this is Tom Russo. You're going to have to speak much louder. We're having a hard time hearing you on this end.

MR. TURNURE: Okay. This is Jim Turnure at ICF Consulting. I was the Project Manager for the Cost/Benefit

Study.

MR. WHITMORE: Thanks, Jim. Is there anybody else from ICF available today?

MR. TURNURE: David Kathen, our Demand Response person is going to join one of these calls, but I am not sure which one.

MR. RUSSO: Was that "David"?

MR. WHITMORE: David Kathen, K-A-T-H-E-N.

Okay, great. Now what I would like to do is go around to all the participants on the call. We have found the best way to do this is alphabetically. So I will call out the letters of the alphabet, and if you could respond for whatever concern you are representing, or if you are just representing yourself by your own name.

Any A's?

MS. CHAMBERLAIN: For Aquilla, it's Susan Chamberlain with Brown, Olson & Wilson.

MR. WHITMORE: Great. Thank you. Other A's?

MR. SMITH: Allegheny Power, Bill Smith.

MR. WHITMORE: Thank you. A's?

(No response.)

MR. WHITMORE: Okay, B's?

MR. MAROWSKI: Don Marowski with Baltimore Gas & Electric Company.

MR. WHITMORE: Other B's?

(No response.)

MR. WHITMORE: C?

MR. THOMPSON: Ed Thompson, Con Edison.

MR. WHITMORE: Thank you. Other C's?

MS. METRICK: Diane Metrick from Connective.

MR. WHITMORE: Great. Other C's?

(No response.)

MR. WHITMORE: D?

MR. DELURE: This is Dan Delure from the Demand Response and Advance Metering Coalition.

MR. WHITMORE: Great to have you. Other D's?

MR. GORRAH: Excuse me. Could we go back to C? I think I had my mute button on.

MR. WHITMORE: Okay, go to it.

MR. GORRAH; It's David Gorrah for Connective from Bruder, Gentile, & Marcoux.

MR. WHITMORE: Okay, great. Other C's or D's?

(No response.)

MR. WHITMORE: Okay, how about E?

MR. GREENLEIGH: From Energy Business Watch, Steven Greenleigh.

MR. WHITMORE: Welcome. Other E's?

MR. FOLEY: Chris Foley from Edison Mission Energy.

MR. WHITMORE: Could we have your name again, please?

MR. FOLEY: Sure. Chris Foley, F-O-L-E-Y.

MR. WHITMORE: Thank you. We always get a lot on the E's from Edison and Electric and so forth. Other E's?

MS. PERAGO: Yes, this is Aaron Perago, Electric Power Supply Association.

MR. WHITMORE: Other E's?

MS. PERLMAN: Yes. Marjorie Perlman for Energy East, which is New York State Electric & Gas and Central Maine, and then also for Rochester Gas & Electric, which is in the process of becoming an Energy East Company.

MR. WHITMORE: Okay. Welcome. Other E's?

(No response.)

MR. WHITMORE: F?

MR. MILLER: For First Energy, it is Don Miller and Tom Bainbridge.

MR. WHITMORE: Thank you. Other F's?

(No response.)

MR. WHITMORE: G?

(No response.)

MR. WHITMORE: G? H?

(No response.)

MR. WHITMORE: No H's. I?

MR. GURLACH: This is Bob Gurlach with Ballard, Sparr representing ISO New England.

MR. WHITMORE: Thank you. Other I's?

MR. EISER: This is Steve Eiser with Ballard Sparr, also representing ISO New England.

MR. WHITMORE: Okay, other I's?

(No response.)

MR. WHITMORE: J?

(No response.)

MR. WHITMORE: K?

(No response.)

MR. WHITMORE: L?

MR. ELDER: For Levitan & Associates, this is Jack Elder.

MR. WHITMORE: Welcome. Other L's?

(No response.)

MR. WHITMORE: M?

MR. STRAUSS: This is Scott Strauss for MWEC from Spiegel & McDiarmid.

MR. WHITMORE: Welcome.

MS. STRAUSS: Thank you.

MR. WHITMORE: Other M's?

(No response.)

MR. WHITMORE: N?

VOICE: (Inaudible.)

THE REPORTER: I need him to do that again.

MR. WHITMORE: Could we start that again, because we had two people talking.

The Power Pool first.

MR. STEINMETZ: Steve Steinmetz from Daybury & Howard, for New England Power Pool.

MR. WHITMORE: Okay, and who else was speaking?

MR. BLACK: Jerry Black, Natural Resources Defense Council, and Project for Sustainable FERC Energy Policy.

MR. WHITMORE: Great. Thank you. Others? Other N's?

MR. LOWENDOWSKI: Yes. Curt Lowendowski for the New Jersey Division of the Ratepayer Advocate.

MR. WHITMORE: Other N's?

MR. KNIGHT: Charles Knight representing the NRG Companies.

MR. WHITMORE: Okay, other N's?

MR. O'HARA: Northeast Utilities. This is Bill O'Hara.

MR. WHITMORE: Welcome. Other N's?

MR. BUELLER: John Bueller, New York ISO.

MR. WHITMORE: Other N's?

MR. DUFFY: Timothy Duffy, New York ISO.

MR. CUTTING: John Cutting, New York ISO.

MR. WHITMORE: Other N's?

MR. FADORAH: This is Phil Fadorah from Northeast

Power Coordinating Council.

MR. WHITMORE: Welcome. Other N's?

(No response.)

MR. WHITMORE: O?

(No response.)

MR. WHITMORE: P?

MR. BUSTARD: John Bustard, Pico Energy.

MS. FOSTER: Denise Foster with PJM.

MR. OTT: Andy Ott with PJM.

MR. LUSTIG: This is Michael Lustig from Power Daily Northeast.

MS. JENSEN: Betty Jensen, Public Service Electric & Gas Company.

MR. WINDERS: PPO Electric Utilities, John Winders.

MS. MEYERS: Potomac Electric Power Company, Mary Meyers.

MR. MONTALVO: Pennsylvania Office of Consumer Advocate, Mark Montalvo.

MR. WHITMORE: Other P's?

(No response.)

MR. WHITMORE: Q?

(No response.)

MR. WHITMORE: R?

(No response.)

MR. WHITMORE: S?

MR. SPARLING: Swidler Berlin. My name is Rick Sparling.

MR. WHITMORE: Great. Thank you. Other S's?

(No response.)

MR. WHITMORE: T?

MS. CRAWSON: Margaret Crawson for Transcanada Pipeline.

MR. WHITMORE: Could we have your name again, please?

MS. CRAWSON: Margaret Crawson.

MR. WHITMORE: From Transcanada.

MS. CRAWSON: Yes.

MR. WHITMORE: Other T's?

MR. SCERRISSON: For Tallis Institute, Frey Scerrison.

MR. WHITMORE: We didn't get that. Could you repeat that, please?

MR. SCERRISSON: Frey Scerrisson, S-C-E-R-R-I-S-S-O-N, The Tallis Institute.

MR. WHITMORE: Great. Thank you. Other T's?

(No response.)

MR. WHITMORE: Okay, let's do U through Z all as one.

MR. FOOT: The Unitil Power Corp., David Foot.

MR. WHITMORE: Welcome. Other U through Z?

MR. MERKIN: The State of Vermont, Hans Merkin, Department of Public Service.

MR. WHITMORE: Thank you.

OPERATOR: Sorry for the interruption, sir. This is the operator. I have an Eli Ferrah who would like to join today's conference call.

MR. WHITMORE: Okay. Welcome.

MS. WALSTEIN: Sandra Walstein, also from the State of Vermont.

MR. WHITMORE: Welcome. Other U through Z.

MS. SHERIDAN: For the Williams Companies, Amy Sheridan.

MR. WHITMORE: Welcome. Others?

MR. FERRAH: My name is Eli Ferrah on behalf of the New York Transmission. I just joined a minute ago.

MR. WHITMORE: Okay. Great. Welcome.

Anybody else that hasn't had a chance to identify themselves yet?

(No response.)

MR. WHITMORE: Okay. Well welcome to all of you, and thank you for joining us. I think we may as well just get started.

Who would like to throw out the first question or comment?

By the way, this is Charlie Whitmore at FERC, still. When you're not speaking, it would help all of us if you could put your mute button on, because we end up hearing lots of papers rustling. Yesterday we had a long strategy conversation from one of the utilities going on in the background which was interesting but probably not what they wanted us to hear.

(Laughter.)

MR. FERRAH: What can you share with us?

(Laughter.)

MR. WHITMORE: Could you say who that was, please, who just spoke?

MR. FERRAH: I was kidding. It was Eli Ferrah.

MR. WHITMORE: I know.

MR. FERRAH: Would it be helpful to have somebody start off with just sort of a brief explanation of the regional issues in the study?

MR. WHITMORE: Jim Turnure, would you like to take a crack at that?

MR. TURNURE: Well, this is Jim Turnure at ICF. Can people hear me all right?

MR. WHITMORE: Yes.

MR. TURNURE: Good. The regional issues in the study. Well, one way to interpret that might be to refresh ourselves between myself and the FERC staff on some of the broad issues that have already come up in these discussions.

Of course we had a call with state regulatory officials from the Northeast last week, and some folks may have better notes on that than I do. I am out in a conference in Santa Fe talking to more state regulators.

Essentially the study has its limits, its scope was limited on a number of fronts, and I think that the first type of issue I would just bring up is kind of the level of detail issues, geographic details, and the sort of time dimension detail, or emparl detail.

We are operating in a national long-run analytic context here. We are taking the entire country over a 20-year period. At the same time, we are operating with a model which can be, if you will, dialed down to further regional detail. Within this study, that leaves us with I think some aggregation issues on the table, and people may want to bring those up in more detail.

People asked about some of the specific regional boundaries in the Northeast. For example, the Delmarva Peninsula, the links between New York and New Jersey, and the treatment of Canadian imports and Canadian dynamics over time. So that is one set of issues, which is more geographic, if you will.

As far as the time dimension goes, a model like this, although it carries a certain level of detail, it can't really address some of the sort of hourly or operational reliability type issues. And we at ICF routinely turn to power flow modeling such as Power World, or sometimes GE MAPS. We use that, too. Some of those issues may be things which people have concerns about. Reliability concerns in particular are a very relevant issue which we only handle in certain regards in terms of reserve margins and the other sort of longer run reliability capacity type issues.

Those are two big areas.

And then beyond that, I think a lot of people are just interested in the particular assumptions, the philosophical approach, and those sorts of issues have come up in a lot of details. You can go down the list of modeling assumptions and scenario assumptions, and talk about each one of those, if people are interested. There will be some informational follow-up which the Commission might want to address.

MR. FERRAH: Well this is Eli Ferrah again. A couple of the ones that you mentioned were ones that were on my mind. For example, what did you assume with regard to Canadian flows?

MR. TURNURE: We discussed that back in the fourth, initially. We can model Canadian Provinces dynamically, and we have the data bases to do that. Because of the national and long-run nature of this effort, we essentially--

OPERATOR: Our interruption. Mr. Whitmore?

MR. WHITMORE: Yes.

OPERATOR: Mr. Whitmore, this is the operator, sir. Are you on line?

MR. WHITMORE: Yes.

OPERATOR: Mr. Whitmore, I just pulled you out of the conference because there's a lot of people that does not have the passcode to join today's conference.

MR. WHITMORE: Um-hmm.

OPERATOR: And we also have Mr. Stuart Kaplan on line that want to join. Is he allowed to, sir?

MR. WHITMORE: Yes.

OPERATOR: And you don't mind, sir?

MR. WHITMORE: Not right now. But, yes, at other times we have.

OPERATOR: Thank you.

MR. TURNURE: --really for model size issues, the compromise was made to treat those imports essentially as--

MR. FERRAH: This is Eli again. What about there are transmission limits between New England and New York?

MR. WHITMORE: Excuse me, please. This is Charlie Whitmore at FERC. We had an interruption from the Operator and as a result we didn't get the full text of what

Jim just answered on the last question. So I am going to ask him to repeat that.

But we also have Stuart Kaplan who has joined the conversation, I believe? Is that right?

MR. KAPLAN: Yes.

MR. WHITMORE: And you're representing?

MR. KAPLAN: NYSIG.

MR. WHITMORE: NYSIG. Okay, great.

MR. GRIFFITH: And Dan Griffith from the Pennsylvania Consumer Advocate.

MR. WHITMORE: Okay, great. Thank you.

Jim, could you go back over your answer to the last question, please?

MR. TURNURE: You had to pick a long one.

(Laughter.)

MR. TURNURE: I was asked to--

MR. FERRAH: The Canadian answer.

MR. TURNURE: I'm sorry? Was someone else speaking?

MR. FERRAH: Yes. He just wants the Canadian answer.

MR. TURNURE: Oh, just the Canadian answer?

MR. WHITMORE: Right.

MR. TURNURE: Okay. Well the model can carry a dynamic representation of a number of Canadian Provinces, actually most electrically interconnected Canadian

Provinces. For this study, because of the geographic scope of the national scope of it, essentially for model, size, purposes, we did not model Canada dynamically in this analysis. We treated those imports at historic levels and essentially left them static. I think that is a brief summary of that answer.

MR. FERRAH: Thanks, Jim. This is Eli again.

What did you assume with respect to transmission constraints between New England and New York? Did you leave those at their current levels? Or did you assume the absence of any restraints?

MR. TURNURE: Okay, well let me just summarize where we originally start from in terms of transmission transfer capabilities.

ICF's wholesale practice, power marketing forecasting practice is continuously looking at and upgrading modeling of transmission transfer limits among other things.

We do tend to stick as close as we can to NERC Reliability Assessments where those are relevant, and we look at the sub-regional assessments, various other types of reports, but we will usually start with a NERC type transfer limit.

Again, we're modeling long-run more or less equilibrium conditions, so we are interested in sustainable simultaneous transfer capabilities. And that is the source for these limits.

Because those are limits between regions, we can actually get good sources for those as opposed to internal interfaces which can be a slightly more customized job, and the sources for that can be more difficult to track down, more difficult to source. But the limits between major regions, we usually have multiple sources for those assumptions.

Now going forward in terms of leaving them alone or changing them, we have a one-time five percent upgrade in the physical limits in the study for regions that are in the RTO policy cases. That is a one-time five percent physical transfer upgrade, and that is designed to capture informational and operational improvements as opposed to major capital upgrades.

We are not allowing any transmission builds in this analysis.

This model can be used with a dynamic transmission expansion component, and the links and constraints in the model are all--they all carry shadow values, if you will.

So even in these runs, there are shadow values associated with the transmission links which represent the value of relieving constraints.

The model can add transmission capability, comparing those economics to generation expansion, for example. That feature is usually not used in this type of analysis precisely because the model will in fact add quite a lot of transmission capability on an economic basis.

People just don't view that as realistic. So in this instance we are leaving those transfer limits static, and I will just leave that for now if you have more follow-up.

MR. FERRAH: No, I think that answers my question. I interpret what you said to mean that you took the existing transfer limits between New England and New York as reported by NERC, and increased them one time by five percent?

MR. TURNURE: Yes. That's correct.

MR. FERRAH: Now if I heard something you said at the Commission meeting correctly, I think you assumed that for, in this case the Northeast, that there was one Standard Market Design in effect across the Northeast? Is that true or not? Did I mishear you?

MR. TURNURE: That is true. Essentially the way the model is operating, it is clearing each regional market as a spot pool, and there is no distinction made between one region or the next in terms of the structure of those pools.

We can do things with contract assumptions, and other things within a model region that could affect how economic dispatch of generation is achieved. But as a normal practice these regional sub-markets, if you will, are in fact clearing under a common mechanism.

MR. FERRAH: And what I am trying to understand in my mind is, to the extent that--and the markets in the Northeast, at least in PJM New York and New England, are very similar. But there are differences.

And to the extent that your study shows certain results between now and 2010, let's say, and the differences in the market design in those three regions are going to take two or three years, or four years, or whatever, to eliminate and end up with a truly common market design that operates under the same parameters, how in your mind does that affect the conclusions in the study?

Is it irrelevant? Is it something to think about? Or is it something that is significant?

MR. TURNURE: Well that is an interesting question. That exact question has not been raised in those terms.

We are introducing a certain amount of inefficiency into this model through the original calibration process. When we use the model to replicate a base year's actual generation, we are including a lot of barriers to trade and implicit stickiness, if you will, in markets.

So we ought to be picking up some of that existing tension between the markets in that process. We could have gone further and actually done some restrictions or constraints on the dispatch within each region to reflect slight differences in market design.

If anything, that would enhance the magnitude of the results, I would think. So I think in brief we've captured the--I would say we've captured some of that through replicating the year 2000 and using those inter-regional trade barriers. But there's probably some more internal, you know, within each region issues with dispatch. So it all depends on how much these market design issues affect competitive plant dispatch within each region.

MR. BUELLER: This is John Bueller from New York ISO, if I can get a word in there, Eli. Since you touched on that, I think it is kind of an important point, as I read your study, as to how you did that initial calibration.

I assume you are talking about this hurdle rate concept?

MR. TURNURE: Right.

MR. BUELLER: Could you maybe briefly talk about how you did that? A specific question I have is that in one place you seem to say that you calibrate to the actual generation patterns and distribution.

In another place you say you calibrate to the power transfers.

Maybe that devolves to the same thing, but I wasn't sure what those two statements meant.

MR. TURNURE: Yes. If you could--if you can find that reference to the power transfers, I would be interested in that. That might be a misstatement. We did calibrate to generation levels to a fair degree of detail within each region, and within basically the fuel mix with the plant types. We were trying to get that whole dispatch mix replicated within each region.

So that was the effort made. And of course what happens is in some regions effectively there are more expensive plants operating in that particular year 2000 than the model would have chosen to dispatch.

So normally what we do is we do a long and complex iteration process where we affect the transmission links between regions, not on the physical limits but on the economic limits. That is why we are calling this a hurdle rate because it is not, strictly speaking, an observable tariff that you could just read off of an OASIS site or a tariff.

Instead, it is an economic charge that forces the model to limit the inter-regional transfers in order to have each region generate on its own in a fashion that it actually did generate in that particular year, the year 2000.

We are calling that an implicit set of barriers to trade, and people can make their own judgments about the long list of various issues and transactional problems that FERC has identified and that we summarized in the first section of the report.

But really, as a strict technical modeling exercise we are using one single model parameter, the transmission charge between regions, in order to constrain the model to essentially backcast the actual year 2000 generation mix.

Then we're using that as the starting point going forward to remove those inter-regional barriers and allow effectively a more efficient or competitive inter-regional trade pattern to emerge.

MR. BUELLER: And then in the base case--this is John Bueller again--in the base case those hurdle rate, those dollar-per-megawatt-hour numbers remain the same for the full 20-year period?

MR. TURNURE: No. They're actually reduced gradually. We reduce them 2.5 percent per year over 10 years. So about a quarter of that inter-regional hurdle rate eases off in the base case.

MS. WALSTEIN: This is Sandy Walstein in Vermont.

Could I ask a clarifying question about the hurdle rates? I think I read in the report, and I may have misread it, that internal hurdle rates within existing ISO regions were assumed to be zero? And only inter-regional hurdle rates were applied for those cases where we have existing ISOs?

Is that right? Could you just clarify that for me?

MR. TURNURE: Yes. For example, one obvious region in the Northeast that has multiple model regions but is one ISO would be PJM. Since we modeled PJM as three distinct regions. So within that area, that's the treatment for hurdle rates.

And then as RTOs are formed that are larger, those hurdle rates between for example PJM and New York would be treated the same way. As they grow, as the RTOs get bigger, more of those inter-regional hurdle rates are essentially taken away.

Now of course the thermal transfer limits are still there. That sort of physical limit that we're not affecting here. But on the economic side, I think you've actually characterized it accurately.

MS. WALSTEIN: Thank you.

MR. ELDER: This is Jack Elder. The physical limits are maintained, though, in the model?

MR. TURNURE: Yes, with the exception of that one-time 5 percent upgrade.

MR. WHITMORE: This is Charlie Whitmore from FERC. I am wondering if there is anybody who has joined the call since our last set of additions?

MR. GUY: I'm Gary Guy from Baltimore Gas & Electric.

MR. WHITMORE: Okay. Great. Thank you. Anyone else?

MR. KATHEN: David Kathen from ICF also joined.

MR. WHITMORE: Hi, Dave?

MR. KATHEN: Hi, Charlie.

MR. WHITMORE: Anybody else?

(No response.)

MR. WHITMORE: Okay. More questions, comments?

MR. GURLACH: This is Bob Gurlach from ISO New England. Does the model predict unit retirements? And if so, do you have the outputs for New England retirements?

MR. TURNURE: This is Jim Turnure at ICF. The model does have unit retirements on an economic basis. There was a time a few years ago when people would assume plant lifetimes. It might be 30 years. It might be 50 years.

These days, plant retirements are treated on an economic basis. And I would comment that the more common outcome for many plants is actually more like a mothballing status. The model essentially can do a few things with a plant that is less efficient. It can either back it down in the dispatch order but keep it on line to receive capacity revenues so it's available for reserve margin requirements, or it can mothball it which sort of gives it an option value.

So strictly speaking, a pure retirement is certainly a possible outcome. On an economic basis, it is actually less common than people might suppose.

As far as outputs go, that is--actually no one has asked about retirements in these calls. A lot of people have asked about capacity additions. The outputs of course are available, but they are the Commission's purview and the Commission I believe--the Commission can make a comment about how they're handling the rather large amount of information requests that are coming in.

MR. WHITMORE: This is Charlie Whitmore at FERC. We are going to be issuing in the next day or two a series of clarifications and other things that we can easily get hold of and are readily explainable to people about this study.

These will include more detailed sets of assumptions about the scenarios, and also the base case, with some explanation of how we got--of how ICF got, or whoever got--why certain assumptions were chosen--

clarification of exactly where the regional splits are, where Delmarva goes, things like that; why Virginia is in the Northeast, issues of that sort.

Some doublechecks on the transfer capabilities to make sure there were no mistakes there.

The RFP for this project back in the beginning, maybe a couple of other things.

There are a series of requests that people have asked for. And as I say, that will be coming out in the next day or two. It will be on our web site, and it will be in the record for all of the relevant dockets. And, Tom, are we sending it out some other way, as well? It will probably be noticed, as well.

MR. RUSSO: We'll probably notice it.

MR. WHITMORE: Now there have been a whole series of requests for other things, including detailed outputs from the model runs, which you have just asked for one piece of, and a lot of other people have asked for other pieces of that; for additional runs for either scenarios or sensitivities that would be different from the ones that were run; for further analysis of some of the results for more regional breakdowns or state specific breakdowns; and so forth.

All of those things involve considerably more work and potentially more explanation and further discussion. For example, the model outputs as I understand it run to sometimes thousands of pages, and to release some of that but not other parts of it simply invites lots more questions.

So what we are going to do with all that is wait until all the comments come in on the 8th, on the 9th, rather, and then we will inventory everything that people have asked for and figure out what to do with all of it.

So if you want more detailed information of that sort, or you want more model runs done, or more analysis of particular things, please put those things into your April 9th comments so that we can figure out where to go from here.

MR. MERKIN: Hans Merkin, State of Vermont.

MR. WHITMORE: Could we have your name again, please?

MR. MERKIN: Hans Merkin, State of Vermont.

Jim, two questions. With regard to deregulation, customer choice, there's very few states that presently have customer choice enacted in their jurisdictions.

What assumptions did your study make with regard to retail access and, depending on your answer, what impact would it have to not consider retail choice?

MR. TURNURE: Yes. This is Jim. That question has come up several times. I will answer part of it, and then I may actually toss a little of that to Dave Kathen because I think part of the implication there has to do with price signals and demand response.

Let me just mention as sort of a major part of the answer, we are not making any explicit assumptions about retail access. The model is really doing a wholesale spot market mechanism. It is incorporating all of the generation in each area.

Now some discussions have been going on about native load restrictions. My take on that would be I generally think of contracts as kind of the unifying assumption behind everyone's discussions of how you treat generators.

When we model these things, we can impose contract requirements on specific plants. For example, must-run plants, whether they're requirements' contract, a QF type contract, or a reliability must-run type contract. Those can be explicitly assumed for specific units.

We made the assumption or the judgment call that native load restrictions, per se, would not cause interference with the economic dispatch process.

You could imagine a situation where integration and native load requirements actually prevent certain units from running, or force them to run, but essentially then you are making the judgment that the native load requirements are actually causing inefficiencies.

We felt it was more appropriate to assume that the efficient competitive dispatch result would be obtained. And then of course there are issues about revenue distribution and essentially who is associated with the cheaper plants.

To some extent that is a separate issue. Structurally you can have this type of wholesale spot market result in a context of fully regulated retail customer service. You can either have the distribution companies separate from the generators, or you can have fully integrated utilities that do own generation. But they are participating in some type of a spot market dispatch clearing mechanism. But they are still fully regulated, and there is still no retail access per se.

MR. MERKIN: Jim, you're going down a path that I think is accurate but my question is a little more focused.

If I were to say retail access is a proxy for customer choice, and customer choice means that they can choose a price responsive response--in other words, if you give me price signals, I can do certain things--that will only exist in a deregulated state with retail access.

If most of our states do not have the ability to react to prices, and since this is an economic modeling exercise, is there a disconnect if you assume that, or do not assume that retail access is going to be in existence?

MR. TURNURE: Indeed. And this is where I was sort of going with this answer in order to kind of get to the point where I'll ask Dave Kathen to say a few words about Demand Response.

I will just briefly say that in my view a fully regulated, integrated, noncompetitive access environment can deliver price signals to consumers. In other words, a fully regulated monopoly utility can indeed choose to provide some kinds of price signals to its consumers without giving them a choice of suppliers.

And with that, I will turn it over to Dave, if you are still there, David.

MR. KATHEN: I'm still here, and I would actually echo what Jim just said.

They clearly--there is more of a price transparency in retail markets, but they are in a nonderegulated state or situation. There is still a capability and an ability to provide the price signals to customers.

An example you can look at are examples like Synergy and Georgia Power and some of the other utilities who are not in deregulated states who are providing price signals to their largest customers.

MR. TURNURE: This is Jim Turner again. So the question then becomes how much do you think that more customers, a broader base of customers, might experience price signals in an environment where there is still not retail access?

Because essentially in the study we are allowing approximately--well actually exactly half the customer base to experience peak versus off-peak pricing. Is that about right, David?

MR. KATHEN: That's about right, yes. And this is a proxy for providing some level of the wholesale market being shown to the customer. It's not assuming that the retail access is needed.

MR. TURNURE: Right.

MR. HELMAN: This is Jack Helman. The posing of the question was how are the results affected by that assumption. If you were to assume say only a quarter of that load at this option, would that materially change the results?

MR. TURNURE: Oh, yes. This is Jim Turnure again. That kind of question has been asked regarding a number of assumptions.

Fortunately for this particular study, that Demand Response in the study is the only scenario that only changed one assumption--namely, the Demand Response assumption. But that scenario can be looked at as kind of a pure sensitivity analysis, or sensitivity case, as well as a policy scenario.

And it is fairly clear from that one-time change in Demand Response that there is a quite significant change in the production costs, in fact the economic benefits measured as production costs. And I think could basically imagine that case being taken down incrementally in terms of the Demand Response, and you should expect to see a fairly linear response, although in regions where Demand Response is affected, essentially you do have some lumpiness because you're deferring the building of power plants to meet peak demand.

So there are some steps and some lumpiness in that response.

MR. HELMAN: Well there's also a fairly nonlinear effect of price volatility, that Demand Response is proposed by some as something that would do away with $1000 prices.

MR. TURNURE: Actually, that is an additional benefit that is really not captured again because of the long run sort of equilibrium nature of this analysis.

MR. HELMAN: So you don't have $1000 prices in any event?

MR. TURNURE: Yes. Right. We will have about 10 demand segments in each region and seasons as well, but the peak price that will typically run in a model like this would be an energy-plus-capacity charge type of a price.

You would never see a $1000 price with a model configured like this, in the long run. So that is sort of an additional benefit to Demand Response that is not actually being captured. And I think in the study we try to point out that short-run market disequilibria, whether it is fundamental based or market power based is sort of an area of exploration, if you will, that is not really part of this analysis.

MR. LOWENDOWSKI: This is Curt Lowedowski from New Jersey. I have a question for Jim Turnure.

MR. TURNURE: Go ahead.

MR. LOWENDOWSKI: Earlier you mentioned that some regional details were considered in the study. I think you mentioned Delmarva area and the New Jersey-New York area? Is that correct?

MR. TURNURE: Yes, that's correct.

MR. LOWENDOWSKI: Can you just explain what those small regional studies encompassed, and what is available with respect to the detailed information?

MR. TURNURE: Oh, okay. Yes, this is Jim Turnure, and I think the easiest way to answer that is to say that the Northeastern State Regulators had a number of specific questions about some of the regional details.

And again, we developed a lot of maps and graphics for this study which really had not been developed before. And as an old geography major, I'm very aware of the level of detail that you offer people is very important. And of course these Northeastern Regions are just physically smaller than some other regions.

So people actually had a hard time understanding and looking at some of the maps that were provided in the report. And I think that the response on our side was: Well, we'll make some better maps for you.

So that is actually going on right now back at headquarters, and once I get a chance to review those maps and put them together, they will be part of the sort of immediate informational response that the Commission staff was referring to.

MR. WHITMORE: This is Charlie Whitmore at FERC. I'm not sure that the question and the answer are exactly on the same wavelength.

As far as I know--and Jim, you can correct me if I am wrong--there weren't any special studies of smaller areas within the Northeast. It is simply a matter of clarifying the larger study and making sure that each piece is--that people know where each regional piece goes, and that the lines showing interconnections are clear and accurate.

Is that right?

MR. TURNURE: Yes, that's right. I think that the suggestion in general going forward might be that more detailed regional assessments may be in order.

I think the Commission has expressed that view, and the question becomes how should that be done, and by whom, and on what basis.

MR. STRAUSS: For example--this is Scott Strauss from Spiegel McDiarmid--with respect to the assumptions that were made about unit availability and efficiency, were those varied in any fashion for the Northeast? Or were these national assumptions?

MR. TURNURE: They are national assumptions. And again they are generally sourced to previous work. Again, there is sort of a traditional most-of-national analysis of electric power competition, and we tried to use existing sources where they were available.

And in this instance, they were applied on a uniform basis.

MR. STRAUSS: I guess my question is: To what extent does the study take into account the existing ISO arrangements that are at PJM and New York and New England that don't exist in many other parts of the country?

I mean, to what extent were any assumptions varied for the fact that those institutions already exist?

MR. TURNURE: Well in the study results that we've got, there weren't any particular approaches to that other than the issue of the transmission hurdle rates within the existing ISOs, which were treated as different.

And as far as the market efficiencies, we adopted a very uniform national approach to that, again partly because we're attempting to break up the categories of potential economic benefit here in order to find out which ones are the most significant.

So rather than get into nuances and more assumptions, really, that is a very obvious candidate for some sensitivity analysis. But in general we adopted a uniform approach and we are just trying to be as clear as we can about what we actually did.

MR. STRAUSS: Thank you.

MR. BUELLER: This is John Bueller from the New York ISO. Maybe step back a little bit.

You said earlier that your model doesn't handle hourly and other reliability type factors such as a GE MAPS model would handle.

Could you describe it, I guess at a high level, but I mean how does--among the cases with different numbers of RTOs, what was defined as "within the RTO" relative to things like "unit commitment," "unit dispatch." If your model is not hourly, does it use load duration curves, or something like that?

MR. TURNURE: Yes. This is Jim Turnure at ICF. I will take a stab at that. You can take that on a number of levels of detail, of course.

Yes, we do use load duration curves and we have an approach to unit availability and unit commitment. Essentially the way it works is for certain types of units, if the model is--if there is an economic role for the unit during a peak period, for example, we have a set of constraints that relate to unit commitment which essentially in simplified terms requires that the unit be dispatched at other load segments in order to be available for the peak or the higher priced load segments.

So that is essentially related to a load duration curve approach. That is one answer to that question.

As far as RTOs and the policy scenarios causing changes or variation in that unit availability and unit commitment approach, that issue did not come up and was not incorporated. I'm not sure--maybe you've got a more specific thing in mind. I'm not sure how the scope of an RTO would affect units' turndown requirements, or their unit commitment approach.

MR. BUELLER: Well what I was trying to get at is to distinguish among, again, the cases with the different numbers of RTOs, what was done within the RTO as compared to across the boundaries between RTOs relative to the unit--

what I would call unit commitment and dispatch.

MR. TURNURE: I see what you're saying. Okay. All right, this is Jim Turnure again. I have to keep saying that for transcription purposes.

Within each RTO market, as I mentioned before, we are operating with one large combined spot pool dispatch mechanism. There are adjustments to reserve sharing and capacity sharing between the regions, and that can affect when units commit and when they don't, it can affect the capacity market essentially.

We do clear energy and capacity markets separately in this model, so although we're reporting annual average energy prices there's actually a separate capacity price that is calculated for each load segment within each region.

Now as RTOs become bigger, more of the sub-regions in the RTO are allowed to share reserve margins and share their capacity markets in a more effective way. So that is one sort of coordination benefit, if you will. But we don't make specific changes to unit by unit availability and commitment. Did that help at all?

MR. BUELLER: Okay, so you mean, as you said before, it is one big pool.

MR. TURNURE: Right.

MR. BUELLER: Within whatever the boundary happens to be.

MR. TURNURE: Correct.

MR. ELDER: This is Jack Elder. Would it be fair to say that, listening to what you're been saying, that the principal effect when you look at say an aggregated Northeast RTO with PJM, New England and New York versus separate regions, the principal effect on the economics is the elimination of the hurdles between those regions?

MR. TURNURE: Yes. This is Jim Turnure again. That is the way we handled it. Although we make the very specific and important point in the document, and I think even in the summary, that the connection between RTO scope and market performance--that is to say, the generation efficiency and potentially even the demand response--to the degree that the scope can be better connected to those efficiencies, the effects, the economic effects of larger RTOs and smaller RTOs would be much more pronounced.

The way we modeled it as a pure sensitivity only affected the transmission's assumptions (inaudible) hurdle rates. So the way it is handled in the study, the way you have characterized it is accurate. I just want to make it very clear that there are some remaining issues regarding how much scope actually matters.

MR. ELDER: There may be some effects that have not been captured in the model.

THE REPORTER: Is that Mr. Elder speaking?

MR. TURNURE: Well the economic issue here is essentially what size is required for effective arbitrage to take place between (inaudible). The downward price arbitrage is really the cornerstone of that kind of competitive efficiency. It is the source of the incentives which want to make less efficient plants performance, and if the scope of the RTO affects whether or not you achieve that kind of price arbitrage, then you have got a much more significant effective RTO.

MR. WHITMORE: This is Charlie Whitmore at FERC. Was that Mr. Elder who asked the last question?

MR. ELDER: That's correct.

MR. WHITMORE: Thank you.

MR. KAPLAN: This is Stu Kaplan. May I follow up on that last question? Hearing no objection, I will continue.

There have been studies showing a lack of arbitrage between New York and PJM. That is to say that even when the price differential for a sustained period of time is multiples of the transmission costs to go between the two regions, the interface is not utilized efficiently much of the time.

Have you attempted to model the inefficiencies that are intrinsic to having two separate dispatch and two separate commitment processes, even if you have common market rules?

MR. TURNURE: This is Jim Turnure again at ICF. We looked at those, and in fact summarized the Merant Study, the New York ISO LECG Response to the Merant Study, and the PJM Study. Those are actually summarized briefly in the report.

Of course they take pretty different approaches. They are statistical. They are retrospective. I guess the immediate direct response would be we only incorporated those inefficiencies to the extent that when we calibrated the model to Year 2000, the dispatch of units between PJM and New York would have been reflected in those inter-regional implicit hurdle rates.

So basically erect an economic barrier between any two regions in the model. And that is designed to show how the competitive dispatch in that particular year was not reflected in reality of how the actual generation differed from what we would view as the optimal dispatch.

So how much of that inefficiency vis-a-vis what you are talking about in transactional terms we actually captured, that is something that needs to be broken down and looked at on a kind of very region-by-region basis.

MR. KAPLAN: Would you agree that any study that is going to compare the relative benefits of having multiple dispatch centers and commitment centers within a region would need to come up with some way of modeling the inefficiencies of having different commitment and dispatch processes?

MR. TURNURE: Well I think that would be a central feature of that type of--

(Loud noise drowns out the speaker.)

MR. TURNURE: --handled it with this inter-regional barrier to trade approach the way it was looked at with, I believe it was the PJM study that actually used GE MAPS to look at an optimal dispatch.

The Merant Study and the response to the Merant Study, neither one of them actually sort of forecast an optimal dispatch per se. They were more looking at what you referred to as price spreads and the question of arbitrage opportunities.

But people can draw their own conclusions based on the magnitudes of economic impacts in those studies, even though they use quite different methodologies.

(Pause.)

MR. WHITMORE: This is Charlie Whitmore at FERC. Are there other comments, questions, clarifications you would like? Any questions about the document that we're going to be releasing in the next day or two?

MR. GURLACH: This is Bob Gurlach from ISO New

England. The tables, they started in the base case I think it's 3.6 and then 3.8 and 3.10, show for NEPOOL an increase in the magnitude of $31 to $36 between 2004 and 2006.

Mr. Turnure, do you know what the drivers or those are?

MR. TURNURE: Yes. Can you point me to the table you're talking about again?

MR. GURLACH: I think a base case is Table 3.6.

MR. TURNURE: Oh, the base case prices. Yes, sure.

MR. GURLACH: But then it's also the follow-on cases, the RTO policy case, the transmission only case, the larger RTO and the smaller case all demonstrate that increase.

MR. TURNURE: Yes. Again, this gets down into some of the output type questions. I think I can make a pretty accurate general comment about what drives those sorts of changes over time.

Usually in both the base case and the policy case as you go forward you are moving from the first couple of years of the forecast in which there are a lot of variations between regions in terms of their current generation mix, their generation status, and particularly the role of what we call firmly planned builds.

Some regions have a lot more capacity currently being constructed than others do. That can lead to very near-term capacity overhang, price declines. And a lot of inter-regional variability in the first few years is driven by where are regions today vis-a-vis their requirements, and what are they building in the immediate term.

That tends to shake out over time in these forecasts, and you will see regions moving towards what you would think of as a long run marginal cost, which really reflects the building and operating costs of natural gas plants, hydro-combined cycles, or combustion turbines, some combination of those to do plant type tends to dominate the build mix going forward, and tends to sit at the margin and set energy and capacity prices.

So over time, generally most regions settle into a price range into the mid-30s for megawatt hours. And initial region-specific changes like a change in NEPOOL from $30 to $36, generally tends to be explained by some of the dynamics that relate to the initial years of the forecast, and I think that that would require more detailed follow-up rather than--I think that gets to a level of output that you would have to ask for more detail on from the Commission.

I hope that helps a little.

MR. GURLACH: Okay. Thank you.

MR. BUELLER: This is John Bueller of the New

York ISO again. Back to the hurdle rate question, or another question rather.

I understand I think that in the methodology you used that the hurdle rates reflect various market inefficiencies, or differences in rules, or whatever, and that it does not reflect explicitly the current transmission tariff charges, if you will, between regions and sub-regions.

But did you make any attempt to identify or use a percentage or something, those actual tariff charges in order to account for the lost revenues of cost shifting?

MR. TURNURE: Oh, yes, the lost revenues. This has again been raised a couple of times in the calls. This is Jim Turnure at ICF.

Basically the short answer is, no, we do not do that accounting. And I would refer to that really as an accounting approach, or a step if you will.

We only carry in the model costs which are relevant for short-run operational decisions and long-run investment decisions.

Among the major cost categories that we don't carry in the model is sunk capital. Whether that sunk capital is generation capital, transmission capital, or distribution capital.

Because most of the transmission revenue today is really a cost recovery mechanism. That all generally falls outside of the range of, you know, directly relevant cost flows.

We view that kind of accounting on a compliance basis quite often, and it could be done for this type of study. But again it is similar to stranded costs of generation for exactly the allocation mechanism for a lot of the revenues that come back to plant owners (inaudible).

THE REPORTER: I'm sorry? Plant owners from?

MR. TURNURE: --specific detailed type of analysis has essentially not been done for this study. There's a reason why, and we think (inaudible).

THE REPORTER: I can't hear him.

MR. GOLDENBERG: Jim, can you speak up a little louder? We can't hear you very well here, for the reporter.

MR. TURNURE: I apologize for that.

We did not do the transmission revenue calculation really because we weren't asked to do it in this context, and it is not something that is relevant for the dispatch short-run results or the operational investments in the long run. That is the type of exercise that could be done, and I would just leave that in the realm of follow-on analysis and things which fell outside the scope of the study, per se, but are still quite relevant.

And of course that gets into some very detailed state-by-state or even company-by-company assumptions in terms of where the revenue flow was before and where it would end up.

MR. BUELLER: Yes, that's correct. Thank you.

MR. WHITMORE: This is Charlie Whitmore at FERC. I am wondering if anyone has joined the call since we last took extra names.

(No response.)

MR. WHITMORE: No? Okay. More questions, comments?

MR. MONTALVO: Yes. This is Mark Montalvo representing the Pennsylvania Office of Consumer Advocate. I just had a question about your treatment of fuel prices and fuel price assumptions.

Did you do any scenario--I didn't notice any, but any scenarios regarding fuel prices and the impact of variance in fuel prices on the kind of present-value of the expected benefits that you calculated? Just because there is a fairly significant difference in the marginal fuel mix in each of the three market regions.

MR. TURNURE: Yes, this is Jim Turnure at ICF. Actually I commented yesterday on one of these calls that I was surprised that people hadn't brought up natural gas prices in particular in the context of sensitivity analysis.

MR. MONTALVO: Well now is your chance.

MR. TURNURE: No, the runs that you see in the report are the runs that came out in the final set of outputs that we provided the Commission.

MR. MONTALVO: Okay.

MR. TURNURE: We were limited in the number of final scenario cases that we were able to conduct. And so most of the sensitivity type assumptions people would be I think normally asking questions about haven't been done, at least not yet.

MR. MONTALVO: Do you have an intuitive sense of what the potential impacts might be? Or is it just you haven't thought about it?

MR. TURNURE: Oh, well--this is Jim Turnure again--the whole key to that would be whether the different gas price is consistent between the base case and the policy cases.

To a large degree, if any sensitivity assumption is changed in both the policy and the base case, in broad terms you expect the effect to be relatively minor. It is more common to have a major effect when the policy might affect gas prices.

For example, in climate change analysis at some point you actually begin to use more natural gas, which makes the gas price different in the policy case as opposed to the base case. If you vary both cases simultaneously, typically those effects are somewhat smaller, although there are a lot of threshold effects when you get down to the regional details, which I guess in principle could be affected. For instance, the ratio of combined cycle to combustion turbine builds in a particular region.

MR. MONTALVO: Right. Okay.

MR. WHITMORE: This is Charlie Whitmore at FERC. More questions, comments?

(Pause.)

MR. COLEMAN: This is Tom Coleman, independent consultant. I would like to ask a question.

MR. WHITMORE: Please go ahead.

MR. COLEMAN: I would like to find out, on that very last point that you brought up about the environmental impacts, were there any environmental impacts looked at in the context of this study in terms of--

MR. TURNURE: Well this is Jim Turnure at ICF. To respond to that, it is worth knowing I think that this particular modeling system was actually developed for the Environmental Protection Agency around the 1996-1997-1998 time frame, and was designed for environmental regulatory analysis, among other things.

It was the one, this particular model was the model used for the EPA's Ozone Transport Assessment Group, the NOx SIPCOL, as it's termed, and is currently used extensively for multi-pollutant legislative or regulatory analysis.

The model does have a lot of detail on environmental regulations, environmental retrofit options, and other--

(Someone sneezes, obscuring the word.)

MR. TURNURE: --options, allowance markets, banking and trading, for multiple pollutants. And those outputs are an integral feature of the run outputs.

That question has been asked in the other conference calls, and it kind of falls in that category of what about more detailed model results.

So to the extent people are asking that sort of question, again the Commission has stated that they're going to have to take all those requests into account and decide how to proceed.

MR. WHITMORE: Jim, this is Charlie Whitmore at FERC. Let me--I wasn't involved in the study early on, but let me see if I understand correct.

At other times, the Commission has used this model or similar things to do environmental impact studies, but in this case my understanding is that there was no effort to model specifically anything having to do with environmental effects, and that therefore any kind of model outputs would be in essence coincidental to the main results? Is that fair?

MR. TURNURE: This is Jim Turnure at ICF. We always carry a set of regulatory assumptions, and in this particular study no effort was made to change those assumptions. Essentially we have--the way we normally model environmental regulations in this context would count current final regulations, and so everything that is on the current Federal Register regarding environmental constraints is in the model.

So there are a standard set of acid rain, Title 5, Title 4, I'm sorry, acid rain constraints, the NOx, SIPCOL, how that is moving ahead. And so all those things are in there, but they were not looked at in any detail by Commission staff during this process. And that was not the intent of the study.

MR. COLEMAN: Just so I understand a little bit better, then. So then the recent announcements about reductions in mercury, for instance, and NOx and SOx, those were not taken into account.

MR. WHITMORE: Could we have your name, please?

MR. COLEMAN: Tom Coleman.

MR. WHITMORE: Thank you.

MR. TURNURE: This is Jim Turnure at ICF. You are referring to the Administration's Clear Skies Initiative--

MR. COLEMAN: Correct.

MR. TURNURE: --which was announced I believe on Valentine's Day this year. That is a--we would regard that as a potential future regulation. But, no, we would not include that as a normal base-case assumption until it was passed into law and final regulations were issued.

But we are not carrying mercury or CO2 or carbon restrictions as a normal base case assumption. We are including current and future changes to anything that is on the books today.

So any other potential environmental regulation, although we analyze those all the time for various clients, that is not part of our normal power market base case.

MR. BUELLER: This is John Bueller from the New York ISO. Were the costs of emission allowances--i.e., SOx, NOx, or anything else--included in the variable costs for dispatch purposes?

MR. TURNURE: Yes, because the way the allowance price is set is through the compliance strategies and the actual compliance decisions that units take. So it is actually that increase in fuel cost, or O&M, or capital upgrade that not only is reflected in the production costs but that is actually what the allowance price is determined by.

There are other costs for allowances and people are exercising the allowance market, banking and trading and so on and so forth. Sometimes that needs to be accounted for separately. But as far as direct costs to clients, yes, that is part of the production cost output.

MR. ELDER: This is Jack Elder. Did your answer just now imply that the model is calculating the allowance costs? Or is it an input to the model?

MR. TURNURE: It's calculated (inaudible).

In GE MAPS, for instance, you have to make an exogenous assumption. But in this model, they are calculated endogenously based on the compliance decisions that the model is choosing to make.

MR. ELDER: This is Jack Elder again. So there would be some inputs to the model regarding what the cost of putting in a cover, or some other compliance strategy that would reduce the amount allowances that would be required?

MR. TURNURE: That's exactly right. Any system element in a model like this has both an economic and a physical characterization. In other words, cost and performance of retrofits.

The COPUS model was used and designed really for regulatory purposes. In the first place, we have a fair amount of detail. So coal plants, for instance, may have a dozen or more retrofit options once you consider combinations for SO_2, NO_x, mercury, et cetera.

So the question is, you know, what order do you retrofit in if it's a multiple retrofit? What about option value? What if you can defer something by using the allowance market for a few years? All that sort of stuff, that's a big part of ICF energy practice.

MR. ELDER: Thank you.

MR. COLEMAN: This is Tom Coleman again. I just wanted to clarify. Then the benefits that were calculated, in some way you're saying they do capture some of the emissions trading that is going on now?

MR. TURNURE: Well I guess one way to put it would be that the current set of limits on emissions, which really are relevant for SO_2 and NO_x at the present time, that is a constraint in the model. It is there. The model has to take it into account as it's attempting to meet electric demand at least cost.

It's another set of constraints like the transmission limits. And so I'm not sure if this question is referring to the value of emission reductions or increases implicitly, but it is an integrated part of the analysis.

It is not something which we would expect to be changed by RTO policy one way or the other. So maybe there is some economic side to it that you are referring to that you could help me clarify.

MR. RUSSO: Jim, this is Tom Russo. I have a question for you.

When we conducted the Demand Response analysis, do our results capture any reduction in emissions since the peak days, often strongly correlated to peak poor air quality days?

MR. TURNURE: Well, yes. Whenever you reduce electric demand, you reduce the need for units. And to some extent, peak units, peaking units, especially existing peaking units, can have relatively high emission rates.

That is a--it is not obvious to me without going over those outputs how big a difference it makes, but generally speaking you would expect to see a pretty strong correlation between demand levels and emissions overall.

MR. WHITMORE: This is Charlie Whitmore at FERC. Are there further questions, comments, thoughts?

MR. EISNER: This is Steve Eisner with ISO. I've got a little bit more of a mega question. I've been wondering about where we could find more detail about the I-Shift model and comparative studies of it versus GE MAPS and so forth, because it seems that there are innate biases in all these models, but there is very little literature on these biases and limitations on model structures.

For example, the modeling of generation in ICF uses a stylized model which does not take into account hour to hour interactions, which are for example important in New

England because of reserve requirements.

And it would just be interesting to know if there have been any studies of how these biases affect output. You know, what direction they affect it. For example, the old Stanford model used to have the Energy Modeling Forum which compared models.

Has there been anything like that for electricity modeling?

MR. TURNURE: This is Jim Turnure at ICF. Yes, the Stanford Energy Modeling Forum 15 was called "A Competitive Electricity Market."

I don't think GE MAPS, per se, was in there. But the Energy Department, and ICF, and Resources for The Future, and a number of other parties looked at competitive market pricing, transmission pricing. That can be found on the Stanford EMF web site.

There is a current, new Stanford Energy Modeling Forum which started in January, and that is designed to consider the effects of diversity in the fuel mix as a hedge against natural gas price shocks. If there are upstream supply disruptions or other unpleasant surprises in the natural gas pricing, how does the electric power fuel mix affect the magnitude of the disruption that would ripple through the economy, basically. That is a new EMF, and that won't produce significant results for quite some time, but information about that can be found again on the Stanford EMF web site.

But it is a good question, and I don't think there is a good, clear source for a direct ITM versus GE MAPS comparison per se, although if I thought more about that, maybe the Center for Clean Air Policy a few years ago in their New York restructuring dialogue, they were using GE MAPS for very similar purposes compared to what the EPA was doing with IPM at that time.

You may need some more follow up on that. I don't think that is too--that doesn't sound like something that would be a problem to get some more discussion about. And there's a lot of information about this model on EPA web sites, if you find the Ozone Transport Assessment Group web sites, this model was gone over by many parties for several years, and there is a lot of information that the EPA maintains on its web site about the use of this model for regulatory (inaudible).

MR. WHITMORE: Jim, could you repeat the last word that you had there?

MR. TURNURE: Yes. I just said regulatory analysis.

MR. WHITMORE: Thank you. We didn't want regulatory "dialysis" for example.

MR. TURNURE: No.

MR. WHITMORE: Okay, are there other comments or questions? Thoughts? Going once, going twice, sold.

Okay, thank you very much all of you for joining us, and please do look out for the clarification document that we will be putting up on the web site shortly, and noticing.

And we look forward to your comments on the 9th and the 23rd of April. I think there have been a lot of good questions asked today, and in some respects I think we have heard from a couple of places that the question of how many efficiencies ISOs have already gained is an important question in several contexts, and that is certainly one that we will be thinking about, and I would encourage you to make sure that that's in somebody's comments.

Again, thank you very much and--

MR. FERRAH: Charlie, this is Eli. Can I ask you one question?

MR. WHITMORE: Sure.

MR. FERRAH: You mentioned earlier that if we had any questions about the studies, or wanted any sensitivity analysis, we could submit those requests?

MR. WHITMORE: Right.

MR. FERRAH: How do we do that, and to who?

MR. WHITMORE: Just include them in your comments on April 9th. We are going to inventory all the ones that we get at that time, and then we will have to figure out on a course of action from there.

I don't think we've--I'm pretty sure we haven't figured out what we're going to do yet. We are not going to be able to pay ourselves for all the things that everybody requests. I'm sure ICF would be more than happy to take the money to buy all of those things, but we'll have to figure out once we get in how many things we can join together and how many things we are going to pay for, and whether there is enough interest for other people to help pay for the other things, and so forth.

So by all means include it in so it is on our laundry list so we can figure out what to do with it.

MR. FERRAH: Last question. If we wanted the power flow information in the Northeast that was assumed in the model, or utilized in the model, is that something we could get access to?

MR. WHITMORE: I really don't--this is Charlie Whitmore at FERC. I really don't know, but put that request in as well. We're going to have to make decisions about all of the stuff that people ask to have, the more detailed stuff and so forth that people ask to have.

I'd say just make sure that it's in the hopper so we can think about it.

MR. FERRAH: Understood. Thank you very much.

MS. JENSEN: This is Betty Jensen from PSG&E. Is there a meeting that is scheduled for the twenty--for next week?

MR. WHITMORE: Yes.

MS. JENSEN: Tell us something about the format for that meeting. Is there going to be a presentation, or is it pretty much the same format at these conference calls have been?

MR. WHITMORE: This is Charlie Whitmore at FERC. We have in mind that it will be very much the same as these calls. We wanted to make absolutely sure that anybody who wanted to had a chance to ask questions and get answers, or reasons why we weren't going to give--couldn't give you answers, or whatever.

So it is simply another forum for exactly the same kind of exchange as these.

MS. JENSEN: Will that be available through Capital Connection?

MR. RUSSO: This is Tom Russo. Right now we are exploring the possibility of doing that. Once we get an answer on that, we are going to be issuing a notice telling you how to do that, if it is available.

MR. FERRAH: This is Eli again. Will that conference be divided by regions during the course of the day, or will it be just free-flowing?

MR. RUSSO: It will be free-flowing.

MR. WHITMORE: This is Charlie Whitmore again. That is I think one of the advantages of doing the conference is that we've heard a lot about region-specific sorts of issues, and it would be interesting to hear how it all fits together.

So bringing the regions together in one discussion I think will be a useful thing to do.

MR. FERRAH: So it will be pretty much question and answer?

MR. WHITMORE: Yes.

Other comments, questions?

(No response.)

MR. WHITMORE: Okay, again thank you very, very much and we look forward to continuing the conversation as we go forward from here.

(Many unidentified voices say 'thank you.')

(Whereupon, at 11:25 a.m., Tuesday, March 19, 2002, the telephone conference was adjourned.)

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