not the way I would put it, but I'm talking -- you're asking me about was there anything that prevented the Commission from filing these things before the FERC, and my answer is yes, because they -- their position was they should review it under Section 32(k) at the state, and so if they were going to review it, they -- at the state, then you don't file a position on it at the FERC. So I'm just trying to answer your question on it.

Q. Okay. That's a strategy decision, would you agree?

A. You're choosing your option, yes. Yeah, it is a strategy decision.

Q. Let me return later to the must-run issue and go on to something else for a moment.

A. Okay.

Q. Would you turn, please, to page 18 of your testimony?

A. Yes.

Q. I'm going to talk about what "normalized" means again.

A. Okay.

Q. At line 13 you pose a question about the rate-making treatment for a prudently incurred cost during a test year that is above the representative (normalized) cost.

A. Yes.

Q. And I want to ask you what you mean by "representative cost" in that context?

A. Okay.

Q. I assume it means the same thing as the normalized cost?

A. Yes, right.

Q. Okay.

A. This is -- if you look at the answer on lines 16 and 17, the answer is "A one-time, nonrecurring expense should not be included in revenue requirements on a going forward basis." And I think that explains what I was trying to convey in my testimony at this time.

If you -- if you're going along and you get an expense, okay, and it's one-time, it's not recurring, then what I'm saying is that -- and you're trying to set rates on a going-forward basis, then you need to do something to normalize that cost, to estimate, in essence, what it would be on an ongoing basis.

You know, if it was just an accident that occurred, you might deal with it one way. In this particular instance, it was the cost of getting capacity reserves -- or, in my view, getting capacity reserves for UE's system, and so the way I answered that is, What would that cost be if we were looking at it on an ongoing basis.

Q. Okay. If I understand what you're saying a representative cost would be, you're -- by the word "representative," you're talking about what's representative as to the future?

A. Yes.

Q. And do you also mean what's representative of the past --

A. Yes.

Q. -- as to the past?

A. Yes, both.

Q. So in coming up with a normalized cost for a particular item, you're looking, in general, at both the past and the future?

A. That's correct.

Q. And with respect to the future, one of the questions you're asking is, is the utility going to incur that cost in the future?

A. That's correct.

Q. Now -- so what does "normalized" mean -- explain to me, if you will, what "normalized" means in the context of a resource planning reserve margin?

A. I -- I don't understand the question.

Q. Okay. I probably garbled it.

In the context of a planning reserve margin, explain to me what -- what is a normalized cost? What do you consider in determining a normalized cost?

A. There is -- boy, and you want that in the context of a planning reserve margin?

Q. Yes.

A. Okay. Planning reserve margin is minimum level of reserves that you target to meet each year in order to provide reliability and in some context a -- provide a hedge against having to buy in the market.

Okay. So in terms of normalization, I think the first question that you ask is, does the utility have that level of reserves and -- and how did it meet that level of reserves? In this particular case, in order to meet that level of reserve for the summer of 2001, UE bought must-run energy from AEM and AEP. Okay.

Q. And it also bought regulatory capacity from AEM. Correct?

A. Yes. Correct. I'm -- if you were to ask the question, will -- was that a one-year contract? Was that a five-year contract? Was that -- what was it, in this case the answer was it was a one-year contract. And will that contract be repeated? And the answer is no.

Then how do I -- how do I set in place or how do I estimate a cost or put a cost in that's representative of what this is going to be on an ongoing basis.

Had that kind of purchase been made in the past, related to the past? The answer is no.

So I don't know if that is the -- I hope that answers your question.

Q. Well, in part.

Would you agree that the exercise that you're going through depends on what you define to be nonrecurring?

A. Yes.

Q. For example, a one-year contract is going to terminate at the end of the one year?

A. That's correct.

Q. And the contract itself will not recur?

A. That's correct.

Q. But, on the other hand, wouldn't you agree that UE would have a recurring need to incur costs to meet the planning reserve margin?

A. Absolutely.

Q. And it would be appropriate to factor those

costs into the normalized cost?
A. That's correct.
Q. Let me ask you this: Would you -- is there a normal -- is there a normal level of nonrecurring costs which you think should be reflected in the normalized costs?
A. Is there a normal level of nonrecurring costs? I don't know. I would have to think about that.
Q. Well, is --
A. What we attempt to do is to remove those from when we -- for rate-making purposes. We attempt to remove those nonrecurring costs, or if -- or we attempt to -- if -- they can be recurring, but they can be erratically recurring.
For example, ice damage from -- or damage from an ice storm, and in those cases we take that cost and we amortize it over, say, a five-year period so that it -- so that the company can collect the dollars that were spent on the ice damage, but it doesn't just shoot rates up and then they have to come back and do a rate case the next year. But that's a recurring. It's just a sporadically recurring cost.
In my view, this is a non-- nonrecurring. It was one that Ameren had to enter into quickly

because of the facts that we talked about before and the timing of it. And so in my view, it's a nonrecurring expense.

Q. Okay. But just so we're clear, I think you agreed earlier that UE will have a recurring need --

A. Yes.

Q. -- to achieve its reserve margin in some fashion?

A. Absolutely.

Q. And generally the options are to buy, build, or to transfer load?

A. That's correct. Well, those are three of the options, yeah.

Q. Are there others that you're aware of?

A. Yes, but I -- you can reduce peak load. You can buy energy back from customers. There's all kinds of demand side types of things that can be done as well.

Q. Okay. Let me ask you questions about -- some further questions about what "normalized" means --

A. Okay.

Q. -- in a weather context.

When you're talking about normal weather --

A. Yes.

Q. -- isn't that determined by deriving an average of what the weather was over a 30-year period?
A. That's correct.
Q. And the actual weather may be above or below the normalized weather and then adjusted upward or downward accordingly?
A. That's correct.
Q. And are you going through the same process when you -- did you go through the same kind of process when you developed your normalized cost for the planning reserve margin context?
A. Well, first of all, I didn't go through a process to determine a planning reserve margin level. I'm agreeing with you that that -- in answering your question in that context. What I did was --
Q. I'm sorry. You're agreeing with what?
A. I agreed previously with your -- you asked me to discuss the concept of normalization within the context of a planning reserve margin, so I put it in that context.

What we did in this case was there were 500 megawatts of purchase and we replaced that 500 megawatts of purchase with 500 megawatts of capacity and included the cost for that 500 megawatts of capacity.

We didn't necessarily look at the reserve margin or say -- or make any decision about reserve margin. This is where Union Electric was in that period, and that's -- so that's what we did. We simply replaced that 500 megawatts.

Q. And that replacement was your normalized cost?

A. Yes. We just norm-- all we did was normalize that 500 megawatts. I have not done any studies on what the planning reserve margin should be or shouldn't be.

Q. And how did you normalize the 500 megawatts of combustion turbines? Explain to me what you mean by that.

A. Well, there were 500 megawatts of regulatory capacity as you've described it that were put in there. There was a must-run energy component that went with that for these months of July and August.

What we did was put 500 megawatts of combustion turbines in instead as -- first of all, Union Electric needed the reserve capacity and peaking capacity, not base load capacity or -- and so we -- we put those in at cost and then ran them as they -- however they ran in Mr. Bender's fuel model.

Q. And when you ran them, is it your

understanding that they were run for the twelve months of the test year?

A. Yes.

Q. Did you -- I may have been confused earlier when you talked about normalizing the 500 megawatts worth of combustion turbines.

Were there any adjustments that you made other than what you've talked about?

A. No.

Q. Okay.

A. We used UE's existing capacity, resource capacity in their contracts, so all of their existing resources, and put in 500 megawatts of combustion turbines instead of the 500 megawatts of contract purchases.

Q. Well, in -- in determining your normalized cost for the 500 megawatts, you did not consider the purchase power market. Correct?

A. No. That's correct.

Q. What if -- well, again in the weather context --

A. Okay.

Q. -- normalized weather, as I understand it, is -- is based on 30 years' worth of weather?

A. That's correct.

Q. But in this case, you just looked at, obviously, a much shorter period of time and just looked at the AEG combustion turbines and used them as a proxy for the 500 megawatts of power that UE purchased from AEM and AEP.

A. That's correct.

But when you say we looked at a much shorter period of time, I'm struggling a little bit with that because what we did -- what we did -- we --

Q. Did you look at any period of time?

A. Yeah. We have a -- in one of the -- let me see if I can remember all of this.

There was -- there was a three-year period of sharing. Then there was an adjustment that was made to rates for UE and then a second three-year period of sharing.

When we got to that adjustment made for rates, there was a weather normalized determination of what that rate decrease would be. In that particular proceeding, we came to a settlement agreement with Union Electric regarding what adjustments would be made to the history, weather history, over a 30-year period. And we used that weather history to come up with the normal weather for the test year, so it's not a shorter period. I'm struggling a little bit with your shorter period.

We take that weather -- for example, we take all of the hottest days out of that 30-year period and we average those. And then we take all of the second hottest days and we average those. And by doing that, we come up with essentially 365 days of normal weather.

Q. Okay.

A. So it incorporates -- now, it doesn't have the variability, if that's what you're talking about, but it has the mean of 30 years of history. So it's not a -- it's not a shorter period.

Q. Well, the AEG units which you selected as a proxy --

A. Yeah.

Q. -- were, I believe, the most recent units --

A. That correct.

Q. -- that AEG installed?

A. They were the most recent combustion turbine units -- simple combustion turbine units that AEG has installed. They have installed other types of units recently as well?

Q. And they were installed during the test year, I presume --

A. Yes.

Q. -- or do you know?
A. I think they were, yeah.
Q. My purpose in asking you about normalized weather was to try to understand by way of analogy whether your normalized cost in the reserve margin context is derived through a thought process which is similar to how you derive a normalized weather value.
And as I understand it, you typically determine normal weather based on 30 years' worth of data --
A. Yes.
Q. -- is that correct?
So when I was asking you about a shorter period that you looked at for the AEG units as a proxy --
A. Oh.
Q. -- I'm understanding you to say that you looked only at the most recent events from the test year?
A. That's correct.
Q. And that you, in effect, did not look beyond the test year?
A. That's correct.
Q. And when you determine your normalized cost, is there some judgment that's involved in terms of the

period of time that you look at?

A. Yes.

Q. And in the reserve planning margin context, is there any objective criteria that you could point to that you use in forming your judgment as to what period of time you looked at to determine your normalized cost?

A. What -- I think I'm going to answer your question, but I'm not sure.

In part, we've already answered it in saying it is the most recent costs that have been incurred for this type of unit for this combustion turbine. So that -- that was really the basis upon which the judgment was made.

So from a time frame standpoint, I didn't want to go back in time and pick units that were -- that were built two -- two years earlier or a year earlier. I wanted to get the most recent units. I didn't want to go back and pick a unit that was a super high efficiency combustion turbine that AEG was planning later to add a com-- a combined cycle portion to it.

That wasn't -- those weren't the types of units that UE needed, so there was a judgment about the type of unit. It was a -- it was a -- it was a combustion turbine, just a basic combustion turbine.

Q. Let's assume again that we're in another rate case one year from now, two years from now. Perish the thought.

But making that assumption, would you be deriving a new normalized cost, or would this normalized cost that you have developed for purposes of this case continue for some period in the future?

A. It's -- that's a -- a very good question, and I've got to put it into a context. So let's suppose we're -- two years from now we come in and we have a test year in which UE has made some kind of purchase that's -- that's nonrecurring. And the question is, do we -- do we use the cost as of that date? And assume the cost is escalated.

Q. And you say -- when you say "cost," you mean --

A. The cost of combustion turbine.

Q. But the AEG combustion turbines? I'm sorry. I'm confused.

A. No. I don't care whether they are AEG combustion turbines or not. I think AEG combustion turbines were a good proxy, okay, and probably would be at that point if they were adding -- adding some combustion turbines. But it would be that -- you know, the cost as of that period, if some escalation had occurred in those, I would include that.

So I wouldn't -- I think I'm -- your question is, well, since it's went (sic) into this case, do we keep the cost at this -- the level we put in today and do two years' worth of depreciation to it, that type of thing? And my answer is no.

Q. So are you saying the normalized cost that you've derived in this case may not be applicable to, say, the rate case one or two years from now?

A. That's correct.

Q. Ideally, it should be though. Correct?

A. I don't know.

Q. Well, the normalized cost --

A. Ideally, we won't have to do this again.

Q. Ideally, the normalized cost should be representative of future conditions?

A. Yes.

Q. Correct?

A. Yes.

Q. So, ideally, the cost that you derive with respect to the combustion turbines as a proxy should be applicable in the future. Right?

A. I'm trying to -- I think from a -- from a very narrow perspective that might be the case.

But let's suppose now Ameren goes out and builds the combustion turbines that fill in this 500 megawatt gap. Okay. If you're asking me would I come back in that case and say, these combustion -- even though these combustion turbines cost a different amount than what you put into this case, would you -- would you argue that they should go in at this price? And my answer would be no. No, I wouldn't.

Q. Okay.

A. At least I don't think I would.

Q. In this case your normalized cost did not include -- did not factor in the price of power at wholesale that was available on the market. Correct?

A. That's correct.

Q. The next time you determine a normalized cost, are you likely to factor in those purchased power costs, or would you exclude them again, exclude them from consideration when you're developing a normalized cost?

A. Let's back up. There's -- there's two kinds of purchased power costs, and I want to make sure that we're clear on this.

Are you asking about purchased energy costs or are you talking about capacity costs, the cost of purchasing capac-- you call it regulatory capacity?

Q. I'm talking about both.

A. Okay.

Q. We were talking about the ways that UE can satisfy its reserve margin requirements.

A. Right. And we're two years from now. Right?

Q. Yes.

A. Okay. What we -- what we might do two years from now depends upon where the wholesale market is at two years from now. Okay. And so I cannot tell you that we would not factor in what's going on in the wholesale energy market. I think we'll have to deal with that in some way two years from now. I don't see how we can avoid it, but -- in dealing with that.

But if you're -- if you're talking about regulatory capacity and whether or not we would look at the market for regulatory capacity, my guess is that we would not. We would look at what the cost to build that capacity is, not to buy it.

Now, having said that, if there is an abundance of capacity and Ameren can enter into a contract for capacity that is cheaper than building it, we would certainly want to take that into account.

Q. Is there any objective criteria that you're aware of to define "abundance"?

A. One of the ways you do it is you -- is you find out information from the market in some way, maybe through an RFP process, as to what that market price is. What you need to have in mind is what term of contract you're buying it for and what your alternative costs are for building.

And, generally, my view is that -- that a purchase of capacity is a -- is simply a delay or I would analyze it as a delay from building, okay, because that -- it's going to be a five-year contract, maybe a ten-year contract. So I'm delaying building that capacity by five or ten years.

So there may be some advantages -- there may be situations in which -- in which there is an advantage to buying that capacity rather than building it.

Q. If I understand what you're saying, if the market gives you results which are more expensive than building, then you would expect the Company to build and you would use the cost of building as your normalized cost?

A. Yes.

(MR. MOLTENI LEFT THE DEPOSITION ROOM.)

BY MR. RAYBUCK:

Q. But if the market was less than the

expense -- if the market price was lower than the cost of building, then what is your result?

A. Well, when you say is -- when the market price is lower than building, I think you have to put that into the context of -- of a present value. It's not a one-year thing. So I want to make sure that's clear.

So you may be looking at -- at something with a 20-year, 30-year time horizon, and maybe you've got a ten-year contract or a five-year contract. And you're looking at the present value of those two, and it's good -- it's prudent to take that choice that has the lowest present value at that point in time when that choice is presented.

Now, in terms of -- let me put that in terms of normalization and try to get that in the context of normalization.

Depending on where the market's at, say, the market is tight, capacity is scarce, and what you will find out is that the cost of buying is more expensive, in your scenario. Your cost of purchasing that capacity is very high.

So at that point in time, you would say, Better decision to build than to buy. And it may turn around very rapidly in the next year or the next two years, that a lot of people have come in and built capacity and there's a lot available and you go to the market and it's cheap. It's a lot cheaper.

And, in fact, it's cheap enough so now it makes sense to buy rather than to build or to delay buying -- or to delay building by the term in the length of the contract.

There's some real trade-offs that occur in those. When capacity is cheap, you tend to get a lower bid price for a shorter contract because the people owning the capacity think, you know, the market price is down right now. If I contract for one or two years, that's okay. But if I start extending at this low price for three, five, ten years, that's -- I need a premium to do that, because five years from now the price may be back up.

If the market is tight and prices are high, then you tend to get better deals on longer term contracts. So you have to analyze all of that. And out of all of that may come an analysis that gives you what the normal is.

Now, I would expect -- I'm not trying to predict, but I would expect that normal would be the cost of building with a reasonable rate of return. So -- so you've got things up here and things down here, but you would expect over time for that to average out, if I can use that term, to the cost of building given a normal rate of return.

Q. What I thought I would do is finish up on this topic for five or ten more minutes and then break for lunch, if you want.

A. Okay. I'm sure I want.

Q. Just to finish up on this concept of a normalized cost, if the actual costings are incurred -- if the actual costs that are incurred are less than the normalized costs, would you agree that the actual cost should be adjusted upward to the normalized level?

A. The scenario is, suppose Union Electric happened to buy this power in a year in which it was really cheap, dirt cheap, and those were the costs that went in. Would I agree that they could argue, Hey, this is a one-time bargain basement deal. It's not going to be like that, and, therefore, we need to make an adjustment? I think I would agree with that, yes.

Q. But in that case, it would be appropriate to adjust the actual up to the normalized level?

A. Yes. That's correct.

Q. Let me ask you some questions about the planning reserve margin.

A. Okay.

Q. And, generally, the Company views these percentages to be confidential.

A. Okay.

Q. So I'm going to try to avoid --

A. Numbers.

Q. -- giving you a specific number and would ask you to do the same. If you feel compelled to give a specific number, just let me know, and we'll make appropriate arrangements. But I'm going to try to be generic with my questions.

Now, I think we've touched on this a bit. For planning purposes, UE is going to a higher reserve margin than what it used in the past in order to provide reliable service. Is that your understanding?

A. Now it's getting hard not to use numbers.

Kind of.

Q. Well, you've had --

A. Let me -- UE had a planning reserve margin that was at a higher -- at a higher level, but in their implementation process would use a somewhat lower reserve margin when they were -- for a year or two ahead.

So what you would see in their planning

studies is next year the reserve margin is at level A, the following year at level A, and then the third year it goes up to level B. Okay. And my understanding is now what they are intending to do is to move level B back to year one and two.

So I guess the answer is, yes, they are -- they are moving up to that higher level for purposes of immediate implementation.

Q. Okay. And you've had discussions with the Company about going to this higher reserve margin. Correct?

A. The Company has made presentations to the Staff concerning this -- concerning their planning reserve margin level, yes.

Q. And, in particular, I believe you've participated in discussions with the Company and reviewed the results of the M.S. Gerber study which analyzed the net costs of having the reserve margin too high or too low?

A. Yes.

Q. And is it correct to say that the Staff supports UE going to this higher reserve margin?

A. I don't know that the Staff has sat down and discussed that in detail, so I can't speak for the Staff on this.

Q. Well, does the Staff oppose UE going to this higher level?

A. It hasn't come up as an issue in a case, so -- what we were asked -- let me tell you what we were asked and what we did do.

We were asked for feedback on the study. Did we have any questions about the assumptions going into the study or the analysis by which the study was done?

I sent Mr. Rick Voytas a list of, I guess, concerns -- that's probably raising it to too high a level -- questions that I had about the study, and they took those to Gerber, and I have received a response on those. I have not reviewed that response.

But as Staff, we have not gotten together and said, Do we have a position on this. And, typically, we don't do that unless it becomes an issue in a case.

Q. Well, do you personally have an opinion as to whether UE should go to a higher reserve margin?

A. I think -- generally, I think that it's important to protect your customers both in the context of reliability and in the context of hedging against high prices in the market.

There is a trade-off. We go to higher --

and we've kind of discussed this. I'm not sure that we've discussed it with the Company.

As you build reserve margin, what you also build is the potential to make more and more profits in the off-system sales market. So as you -- and we just haven't worked through all of that. Part of this is you can't separate those pieces. You can't say, Hey, we're going to put in X amount of reserves. That gives you a greater potential to sell in the off-system sales market, so how do we incorporate that into a rate-making context?

And, basically, my understanding of the Company's study is that's what it -- that's what it did. It said, Okay. I'm putting more reserves on, okay, I'm going to be able to sell more in the market, and I'm going to be less dependent on the market.

So as I move to a certain level of reserves, as I go past that, I can sell more and more in the market, but does the incremental amount of my sales offset in a sense the cost of this new capacity that I put on it, or if I have real low reserve margins I'm not going to be able to sell very much in the market, but I have to buy a lot, and I'm at risk when I buy, so does -- as I move my reserves up, that risk goes down and the ability to sell in the market goes up.

So where is kind of the optimal place that you want to be?

I support that analysis. That's what I'll say. I support that -- that is the way to analyze the problem.

Q. Okay. If I understand what you've testified to, the Staff has not examined UE's decision to go to a higher reserve margin, and, therefore, there is no formal decision by the Staff to support that?

A. That's correct.

Q. However, you believe that given the trade-offs that you were talking about, that that's a reasonable thing for UE to do?

A. I believe that the analysis they performed was a reasonable analysis to perform, yes.

Q. And do you think --

A. I had some questions about the results that were coming out, and I'm -- I'm just not sure of those. I've gotten some feedback. With everything else I've had to do, I haven't had a chance to go back through that, so if you're asking me is this number a reasonable number, I can't -- I can't -- I cannot tell you that today.

Okay. If you're asking me do I think the type of analysis that UE had performed, was that a reasonable type of analysis, my answer was yes.

Q. If you -- when UE goes to a higher reserve margin, that will mean that UE will incur more plant O&M and capital costs in the future as compared to the lower reserve margin?

A. That's correct.

Q. And would it be reasonable to have UE reflect the additional costs in rates to get to this higher reserve margin?

A. Give me a context. Are you saying if it's determined that the higher reserve margins are a reasonable target, the answer is yes. Yeah.

Q. Well, would you agree that the higher reserve margin should be factored into the normalized cost?

A. If it's determined that that's a reasonable level, yes.

Q. But you're not committing to that being a reasonable level; is that correct?

A. Well, that's what I said before. I don't know if the specific number that they are coming up with is reasonable or not. I -- what I'm saying today is that the -- the analysis that they -- that they did appears to be reasonable.

Q. Well, is there more information that the

Company can give you in the near term to satisfy your concerns as to the adequacy of the analysis that the Company did?

A. As I said, I sent my comments to Mr. Voytas, and they conveyed those to Gerber, and I've gotten some response back from that. I have not had a chance to review that. So I'm assuming that that may -- that information may be sufficient. I just have not reviewed it.

Q. If the analysis is -- is an adequate one and if UE is going to be incurring these additional costs, then shouldn't they be factored into the normalized cost?

A. Yes.

MR. RAYBUCK: Okay. I'm finished for now.

(A RECESS WAS TAKEN; MR. CYNKAR, MR. COFFMAN, AND MR. ZUCKER LEFT THE DEPOSITION ROOM.)

BY MR. RAYBUCK:

Q. Yeah. Would you please turn to page 18 of your testimony?

At line 18 you talk about the lower cost or market principle. And what is the source of that principle? Where did it come from?

A. You're using the word "principle" -- I just used that word to describe a utility -- to describe the concept. I didn't mean it as if it were some principle that somebody had established somewhere.

Q. Well, you refer to it in your answer as a principle. Correct?

A. Yeah.

Q. And what is the source of it?

MR. DOTTHEIM: Mr. Raybuck, in particular, would you like to direct Dr. Proctor to a certain line or line numbers?

MR. RAYBUCK: I meant to. If I didn't, line 20.

BY MR. RAYBUCK:

Q. The question beginning at line 18 and going through line 21, you state there that the utility should be at the lower cost or market and you talk about the principle keeps the affiliate from abusing the utility.

A. Right.

Q. And the question to Dr. Proctor is, what is the source of this principle?

A. Right. Is there -- let me see if I understand your question.

You're asking the question, is there somewhere published or discussed or presented -- this thing is presented specifically as a principle? Is that -- is there some source besides just the discussion that's in here?

Q. Right.

A. The -- this was expressed in the Missouri Commission's Affiliate Transaction Rule.

Q. Do you know whether UE is subject to these rules?

A. My understanding is that UE has that under appeal.

Q. And --

A. And I believe there is a stay, but I'm not sure, so that they may not be under it.

Q. You believe there is a stay as to the rules in terms of whether they apply to UE?

A. Whether they apply to UE until the appeal is completed.

Q. Would it be fair to say that you have in effect applied the Affiliate Rules to this AEM/UE contract?

A. It would be fair to say that because I did use the cost of the combustion turbines to normalize that I am applying that principle here or those rules here.

Q. Okay. Thank you.

Turning over to page 19, please, beginning at line 18, you discuss new generation capacity built by AEG. Do you see that?

A. Yes.

Q. And, once again, I'm going to try to avoid getting into the confidential material.

A. Okay.

Q. And at the top of page 20 you refer to your schedule 3, and that shows confidential information concerning AEG's reserve margins. Correct?

A. Correct.

Q. Excuse me. Do you know if more current information is available as to AEG's reserve margins?

A. I assume that it is. This was information that was requested and was supplied in January of 2000.

Q. Okay. Do you -- do you have more current information in your possession as to AEG's reserve margins?

A. I believe I do.

Q. Is there any reason why you didn't use that more current information?

A. Yes, there is. This information was in terms -- was put in in terms of the context of the time at which Ameren made the decision to begin to build new generation capacity in AEG rather than UE, so I was wanting to put this information within the historical context. And this was the -- so this planning, these documents, reflect what was going on at that time.

Q. Okay. And do you know generally what's going on currently in terms of AEG's reserve margin?

A. I'm generally aware of that, yes.

Q. Do you know whether they've come down, stayed the same, gone up?

A. I'd have to look at the specifics. My general impression is that they have come down, and -- but I don't know whether it's going to decrease in peak load forecast or a decrease in what they're planning to add as generation. I can't tell you specifically. But my general impression is that they have come down.

Q. Okay. So this data that you used comes from -- it was provided to you in January of 2000 --

A. That's correct.

Q. -- correct?

And since January of 2000, UE has built some plant itself. Correct?

A. Yes, that is correct.

Q. And UE built a 50 megawatt combustion turbine at Venice. Are you familiar with that?

A. Yes.

Q. And UE is building a number of combustion turbines for placement at Peno Creek in Missouri?

A. That's correct.

Q. And Peno is, I think, P-e-n-o.

And a combustion turbine was built by UE and sited at the Meramec Power Plant?

A. That's correct. I think I discussed that one in my testimony, the Meramec.

Q. At line 20 on page 20, it looks like you did.

A. That's correct.

Q. Did you discuss the others that we just went through?

A. No.

Q. Now, do you have an opinion on whether electric utilities have been reluctant to build generation in the last several years? Do you have an opinion on the subject?

A. Do I have an opinion on whether they have been reluctant? Is that the question?

Q. Do you have an opinion on that subject?

A. We have seen that some utilities have expressed a reluctance to build generation. We have also seen utilities that have not been reluctant to build generation, so it's kind of been a mixture of each.

Q. Okay.

A. I think it's -- I think it's a question of whatever specific situations that they are in. But, yes, I've seen that reluctance.

Q. Well, are you able to -- for those utilities that have expressed to you some reluctance to build, are you able to -- can you generalize for me the nature of their reluctance?

A. Actually, when such a reluctance was expressed over here to the Missouri Legislature, all right, by Gary Rainwater, I approach Mr. Rainwater and asked him. I said, I don't understand. Help me understand what the reluctance is. And what he expressed at that time was that -- I don't know if I can describe it real well. I'll try.

Q. Well, first of all, time out for a minute.

A. Yes.

MR. RAYBUCK: Was the -- could we go off the record a second?

(A DISCUSSION WAS HELD OFF THE RECORD.)

THE WITNESS: What it was was a more detailed explanation of Ameren's reluctance to build utility -- to build generation in a regulated utility, not so much a reluctance overall for a utility to build, but where -- where it would build. And the context was what we called the Genco bill, and that was to transfer all of the regulated assets to nonregulated Genco and then go through a FERC cost of service determination of cost for the regulated side.

And my understanding is that -- that there was a concern about the regulated utilities being permitted to build the level of reserve margins that were needed to cover -- to cover them in the market, the hedging thing that we've talked about before. And if all of the assets were transferred to a Genco and then you had a power supply agreement, that I guess, in essence, the Genco would take all of the market risk, okay, and the transfer would just be at cost, and that way they would be able to -- to manage that market risk. So that's kind of the explanation that I heard.

It wasn't -- if you get into a little bit more detail of it, and it goes back to the issue we were talking about before, if you build up your reserve margin as a regulated utility, okay, you build up your reserve margin, now you have more capacity to sell into the wholesale market, so when prices are high, you're going to make more money than you made before.

And now -- from a regulatory perspective, now you have to deal with that, because there is -- you know, do you just throw it -- throw the bucks in for the plant, or is there some offset to that that comes from -- from off-system sales? And it's -- you know, to me it's just a regulatory -- a regulatory process that you have to deal with, is coming up with that balance.

So I think that's where I heard the reluctance, was regulators aren't going to allow us to do this. They are not going to allow us to stick in the level of reserve margins that we need to put in. So that was the one explanation that I've got.

Prior to that, when -- this was years -- several years ago, when everybody was concerned about stranded cost, that was the other argument that we heard from utilities and utility plant. I know -- I'm concerned about building new plant, and then when we go to retail competition, the cost of that new plant is going to get stranded.

And so a lot of utilities -- or not a lot. Some of the utilities were looking at purchased power -- power sales agreements, shorter term, so they wouldn't get stuck with just stranded cost if we went to retail. So that was the other. I haven't heard that argument for probably three, four years now.

BY MR. RAYBUCK:

Q. Well, I'll try to summarize based on statements that were made to you by Mr. Rainwater and based on the kinds of factors that you talked about in your answer.

A. Yes.

Q. Is it your understanding that there is some reluctance by some utilities to build?

A. There has been in the past, yes.

Q. And that reluctance is based in part on market-related risks?

A. Yes.

Q. And those market-related risks are a function of deregulation and the evolving competitive markets?

A. That's correct.

Q. And so, for example, if Missouri ever deregulates the generation of electricity at retail to allow for retail competition, that's a kind of market risk that UE could face and might result in stranded costs if UE had built generation. Is that what we're talking about?

A. I think in part it is, yes. If someone else is willing to take on that risk, an IPP, independent power producer, or someone else is willing to take on that risk and make -- and offers to sell you power, and that's -- that may be cheaper than what you can build it for. Okay. There is probably not much of an issue about what you will do.

However, if -- if that contract is maybe more expensive, okay, if I'm doing a 20-year analysis, and that contract is more expensive, and I may want to factor in the risk -- I may want to shorten the time horizon because of this -- this risk of deregulation. It may lead you to -- to buying even when the longer term analysis says it's cheaper to build. And that's where -- that's where it would make a difference in my view.

Has anyone brought such plans to us as a Staff, and said, Well, we've looked at this and we've done a 20-year analysis, and while it's cheaper to build than to buy, okay, we're going to buy anyway because of this risk. That has never happened. That has not happened.

Q. Would you agree that in general these market risks and deregulation risks that you've been talking about act as a disincentive to utilities building?

A. I don't know. I have not seen that. If you're saying is -- if I'm given the choice between -- let me put it in -- your question in context.

The utility has to get the capacity to serve its native load from somewhere so it's a set of choices it looks at. And if your question is, does -- do these market risks affect the choices that utilities make and their decisions, my answer is yes, absolutely. And should they? Yes, they should. Okay.

Q. And my question to you is, were these risks the market risks, the deregulation risks, do they serve as a disincentive --

A. Disincentive.

Q. -- when the utility makes that choice?

A. We have not seen that. We have not seen a study where, for example, a different discount rate is used for buy versus build, or we have not seen a study where the time period that was looked at was shortened because of the buy versus build. So I haven't seen it in that context.

The context that I would put it in is one of what we have seen is we need -- we need to find some way to hedge the market risks, so, for example, increase our -- increase our reserve levels or something along that line.

Q. What about regulatory uncertainty? Would you agree that that could be a disincentive to a utility building new generation?

A. Versus buying?

Q. Yes.

A. Okay.

Q. Or versus transferring load?

A. Or transferring load, right, the other alternative.

Repeat the -- repeat the first part.

MR. RAYBUCK: Can you read it back, please?

(THE REQUESTED QUESTION WAS READ BY THE COURT REPORTER.)

QUESTION: What about regulatory uncertainty? Would you agree that that could be a disincentive to a utility building new generation?

THE WITNESS: Boy, regulatory uncertainty probably needs to be defined in this context. And there are various aspects of that, but regulatory uncertainty about what's the rate of return I'm going to be allowed, regulatory uncertainty about prudency, those types of things.

I don't know if those affect the decision or not because I -- I would think most of those uncertainties, though I haven't gone through and categorized them or cataloged them in my mind, but might be there for both -- all three of the alternatives that we're talking about, buy, build, or transfer. They could be there for all three.

So I don't know. I guess my answer is, I don't know.

Q. When a utility purchases capacity and energy, there is no return that's typically allowed for such a contract. Correct?

A. That's correct. It's an expense.

Q. A return would only be applicable in general to an investment --

A. Uh-huh.

Q. -- whereby the utility would build, own, and operate a generating unit --

A. That's correct.

Q. -- correct?

So if the rate of return is perceived -- or the expected rate of return is perceived by the utility as being too low, could that be a disincentive to the utility in -- in deciding whether to build versus to buy or to transfer?

A. I have to work that through the capital markets kind of.

If the utility knew for certain that its decision to buy -- that all of those costs that it paid out as expense would be recovered, I -- and the other option was to build, and unsure about what the rate of return is going to be on that, so I've got one fixed option and I've got another that has some risk associated with it, that could be a factor in the decision.

Now -- but there may be a different type of regulatory risk that's associated with the purchase option. So I may have risks in both of those, is, I guess, what I was trying to say before.

I -- until you take -- see, the decision isn't -- it isn't a univariant decision. It's not to look at a single risk. It's to look at all of the risks that are involved and all of these options and then make that decision.

Q. Well, if a utility elects to build generation, it would have construction-related risk. Correct?

A. Yes.

Q. And you would not have that if you purchased?

A. That's correct.

Q. And you would not have that if you transferred load?

A. That's correct.

Q. And if you decided to build, you would have -- you would face -- you would incur risks related to strandard -- pardon me -- to stranded costs for the lifetime of that unit. Correct?

A. Well, the stranded costs -- let me back up and take each piece.

The cost to build, the risks associated with that are much larger for -- or probably the largest for the nuclear plants, somewhat smaller for coal plants, and for combustion turbines, they turn out to be very, very small.

The stranded cost argument is simply a trade-off of who's willing to take the risk. Now, if I go -- if I am willing to take the risk, what I'm saying in essence is I'm willing to build a combustion turbine now or a plant now to meet my load requirements now and then be in the market when it deregulates.

Okay. And when I'm in the market and it deregulates, what people called stranded cost is the fact that I may not earn the same rate of return that I'm earning now selling to the regulated load because the market price may be lower.

Okay. So at the point that the decision is made, what you're looking for, in essence, is someone else who's willing to take that risk, who's willing to build a plant now, okay, sell it to you and earn whatever they can from it, and then when they deregulate, they're taking on that risk at a future date.

So in part, what can happen in a competitive world is if we have a lot of competitors out here building generation, and there is a surplus, that price can get driven down, and when it is, I absolutely would stand behind a utility entering into a power supply agreement at that point.

Okay. When that -- because competition has driven that price down, what -- you're kind of in this position of, We've overbuilt capacity in this area. It's a sunk cost for me now. I've got to recover what I can recover on this to make it through to times when prices are going to get higher. And you may be able to buy some deals at that point.

If, however, there is a scarcity, it doesn't make -- and that's really the context, I think, you're talking about. When there is a real scarcity of supply out there and you've got to make a decision about to buy or build, okay, and prices -- current prices are high, I don't -- I'm having a hard time -- I'm struggling with the concept that I would -- because I'm concerned about stranded costs out here when the prices are high right now of not building. I don't understand that. I just -- it doesn't make a whole lot of sense to me.

Q. Okay. Let me turn to a different topic now.

A. Okay.

Q. Could you turn to page 21 of your testimony, please?

A. Okay.

Q. At line 3 I'd like to revisit this must-take energy concept.

A. Okay.

Q. And beginning at line 3 you refer to the contracts that UE entered into for the summer of 2001?

A. Yes.

Q. And you indicate that those contracts required UE to take must-take energy?

A. Yes.

Q. And you define it there.

And the two contracts again that we're talking about is the AEM contract and also the AEP contract.

A. That's correct.

Q. So is it your understanding that the AEP contract had a must-take energy provision?

A. That was my understanding, yes.

Q. Okay. Now, at line 10 you testified that had corporate planning performed an analysis of whether the must-take energy would have been least cost, it would have requested bidders to submit proposals that did not require must-take energy and they could have made a comparison?

A. That's correct.

Q. Now, did you or anyone at Staff perform such an analysis?

A. I did perform -- after the bids were in and evaluated, I did perform a -- an analysis that looked at given what I thought at that time was the cost of the combustion turbine and the cost -- the energy cost, I was looking at how many hours it would take to run that combustion turbine in order to be equal with this must-take energy.

Q. Was that analysis that you performed done in conjunction with your determining the normalized costs?

A. No.

Q. That was a separate analysis?

A. Right. This was -- this was an analysis I did at the time that we were told about it.

Q. Now, if I understand what you're referring to, you were -- you contend that corporate planning should have done an analysis with respect to energy that would give UE a fixed price but was not a must-take?

A. Yes.

Q. And do you know whether suppliers selling for the summer of 2000 were willing to submit this kind of product?

A. I guess my -- I believe there were some bids initially submitted that allowed dispatchability, and that's what we're talking about, a fixed -- to be dispatchable at a fixed price, and -- but when both *Burns & McDonald -- was it Burns & Mac, I think, that* did the evaluation -- and Ameren did their evaluation, it was all done on a must-run basis.

And, then, again, my understanding is they went back and said in this second round or second RFP, We wanted all of the bids to be -- there submitted to be must-run bids. That was a requirement on the second run.

So were there some bids submitted in the first round that were -- that had dispatchable energy in them? And my answer is, I believe there were. And --

Q. And by dispatchable energy, you mean energy that would not be must-take?

A. Must-take, yeah. I can take it -- here is the price for it, and I can take it if I need to buy it at that price.

Q. And so it's your assumption that some bidders initially submitted bids to this effect?

A. Yes. That's my reading of the response of the bidders.

Q. And do you know whether those bidders were willing to offer that product at a fixed price?

A. Yes, they were.

Q. That's your understanding?

A. That's my understanding.

Q. Let me ask you this: Would you agree that the supply and demand conditions in the wholesale market that were applicable at that time could influence whether or not a supplier would offer a fixed price product that was not must-take?

A. Let me -- I'm an economist. I believe if you --

Q. So you understand supply and demand?

A. Yeah.

Q. I know that.
A. Yeah. And part of it -- and I don't want to be rephrasing your question, but I don't look at things that way.
Whether people are willing to do something or not, the question is what price -- they are willing to do it. It's just what price are they going to charge in order to do it. I mean, I just look at it that way.
Q. Okay.
A. There is a price -- there is a price that they are willing -- if you want dispatchable energy at a fixed price, there is a price that somebody will offer that at.
Q. Wouldn't that be at a price that's likely to be much higher than a fixed price, must-take product?
A. I would assume that that's true.
Q. And did you make -- in the analysis that you did that you referred to, did you determine the higher price of that fixed price, nonmust-take product as compared to the fixed product -- fixed price, must-take product? Did you do a comparison?
A. Not the comparison that you're talking about, no.
I mean, I didn't -- I didn't try to derive

what the price would be if I was offering a dispatchable product. That's not what I did.

What I did was I said here -- I just did a comparison to cost. If this is -- if this is what the demand cost is, okay, the fixed cost, and here is what the gas price is, and here is what the heat rate is, from -- from a cost basis, how much -- how many hours will I have to run in order to cover this must-run?

See, the must-run contract was not split up -- I was trying to find out -- trying to get to an energy and demand component. The must-run contract was, I believe, $X a megawatt hour, period. And then it -- or did I -- I'm sorry.

Q. That might be confidential.

A. I think I just messed up.

MR. RAYBUCK: Go off the record for a minute.

(A DISCUSSION WAS HELD OFF THE RECORD.)

BY MR. RAYBUCK:

Q. You were saying.

A. Okay.

Q. X dollars.

A. The must-take was at X dollars per megawatt hour. And what I was doing was trying to get to, given costs, given a demand cost for the combustion turbine, so many dollars a kilowatt, and a fuel price and a heat rate, how many hours would I have to run that unit in order to recover the same dollars that were -- that were -- that was in the X dollar per megawatt hour contract.

Q. Looking at the combustion turbines that AEG put in, were those the units that you were using?

A. This was -- I think at that time, no. I think what I was using was a more generic combustion turbine cost. It wasn't that specific.

I was -- you asked if I did -- I was just trying to get a feel for where this contract stood in relationship to cost, or what was perceived to be cost at that time.

Q. Okay.

A. Actually, if you compare it to the prices today, it had a lower fixed cost and a much higher variable cost. The higher variable cost came from what people were -- from what they were looking at in terms of futures gas prices at that time.

Q. Okay.

A. And today those prices are much lower.

Q. And, in fact, those prices can change on a daily basis?

A. They can, yes.

Q. The price that you quoted earlier, X dollars, that was a bid given on a particular date?
A. Yes.
Q. And if you -- if a bidder -- a supplier submitted a bid a month later, it might be very different from X?
A. That's correct.
Q. And you refer -- do refer to this, I believe, at line 19.
A. On page 21?
Q. Yes. At line 19 you refer to future prices for must-take energy.
A. Right.
Q. If I understand what you're saying here, the phrase "future prices for must-take energy" involves a proposed price on day one, for example, the day you submit the bid for delivery at a future time?
A. Yeah. Actually, I think this is -- a future price would have been a more formal type of thing. It would have been what, for example, the future price that Cinergy was that was being reported at this time ahead of time.
So a futures price, it is -- it's a contract, but it's not a bilateral contract. It's a trading of futures in a commodity, so that's what I

was referring to there, is the futures price for energy, must-take energy that -- you're buying a product. That product is a must-take product. It's a five-by-sixteen, or sixteen hours a day on peak five days a week. That's the product that's being bought and sold in the futures market.

Q. Okay.

A. And so that's what is being referred to here is futures price.

Q. Okay. And to apply that to this context, if I understand what you're saying, we're talking about somebody submitting a bid in February, say February the 5th, and their bid represents the price that they will charge for delivery in this case starting in the summer of 2001?

A. Correct.

Q. And that supplier can go to a publication and can get some idea as to what those -- what that future price will be as you have referred to it?

A. Yes.

Q. And if somebody submits a bid on February 6th, the very next day, that bid could be -- could reflect a price very different from what the bidder -- another bidder gave the previous day?

A. Sure.

Q. Let me put it a little bit differently. UE, if it wanted to hedge market risk, having to buy in the market, could have bought futures in Cinergy. If, say, the market price goes way up, then they are going to have to pay a lot for the energy, but they can -- they will have that futures and they will be able to sell it and make a lot to cover -- cover their higher costs. So you can hedge -- you can hedge market risk through buying futures or selling futures or if they are derivatives, you can buy those as well, which is an option to exercise this.

But what they would be missing if they went that route was the capacity, the reserve capacity.

Q. Okay. Let me ask you this: The price that a supplier would bid would be a function of -- would be based on an assessment that that supply -- would be based on that supplier's assessment of market conditions --

A. Correct.

Q. -- supply conditions and demand conditions?

And if suppliers thought that demand conditions were such that a -- well, strike that.

Let me -- let me -- let me give you a simple example to try to convey this.

Let's say that I'm in the business of

selling oranges, and my assessment is that there is a high demand for oranges, and I think that there is a minimum take that buyers are going to be willing to live with, generally speaking, because of the market conditions. And let's assume that I, as a seller, expect that the minimum take for oranges is ten oranges.

Now, given that assessment of the demand conditions, that's going to affect how I price the supply of oranges. Correct?

A. Okay.

Q. Now, if you just want to buy one orange from me, isn't it likely that I'm going to price that orange higher than I would for a product whereby a buyer has a minimum take of ten oranges?

A. Sure, yeah.

Q. Okay. So in other words, if I can sell an orange -- why should I sell one orange to you for $1 when I can sell ten oranges to Mr. Kind for $10, if I'm doing the math right?

A. Correct.

Q. Okay. Now, prior to the issuance of the RFP by the Company, did you ever have any conversations or discussions with Company officials whereby they told you that it was not possible to get a fixed price product without a must-take provision? Did the Company ever make statements to you to that effect?

A. Not that I recall.

Q. Okay. Is it -- is it your -- I mean, do you have evidence that suppliers were willing to offer a fixed price product in the winter of 2001 for delivery in the summer of 2001 that did not have a must-take component?

A. I believe there were some initial bids where energy was dispatchable.

Q. Do you recall what those bids -- or who submitted those bids?

A. I believe one of them was submitted by AEP, but I'd have to go -- I would have to go back through all of the -- all of the responses to the RFPs to see, but my recollection right now is that one of those bids came from AEP that was dispatchable.

MR. KIND: Might that be confidential?

MR. RAYBUCK: Well, I guess I haven't heard anything yet that bothers me. We did enter into a contract with AEP.

MR. DOTTHEIM: I'm sorry, Mr. Raybuck.

MR. RAYBUCK: I'm fine continuing.

MR. KIND: Sorry to interrupt.

MR. RAYBUCK: I appreciate that.

BY MR. RAYBUCK:

Q. Did you finish your answer?

A. Yes.

Q. This bid of AEP that you're referring to, do you know whether that led to the contract between AEP and UE?

A. I assume it didn't because it was in the first round. And my understanding is that the second round or the second RFP was all must-run.

Q. Okay. Well, going back to my homely example about the oranges --

A. Uh-huh.

Q. -- if you apply that to electricity, wouldn't the same principles apply, namely if I'm a seller of electricity and I know or I have reason to believe that the market is such -- excuse me -- that the demand is such that a minimum for a must-take product is a common product, and if someone wants me to offer them a fixed price that did not have a must-take provision, isn't it likely that I would in my fixed price offer to that customer -- bid a price that would be much -- it would be higher than a product that was a fixed price, must-take product?

A. Sure.

Q. Okay. And if I understood you, the analysis that you performed, that's the kind of analysis that you expected Corporate Planning to make; is that correct?

A. No. No. My analysis was after the fact. You asked me if I had done any analysis of this. Maybe I should have answered no.

The analysis that I think Corporate Planning should have done is similar to what they've done for this year, and that is they invited all kinds of bids, okay, which include -- could include must-take, could include dispat-- what I would call dispatchable, could include fixed price, could include indexed, so if you -- if the supplier didn't want to take on the risk of a gas price, could -- could index the variable cost to gas price index.

I mean, there would have been all kinds of options that -- that they looked at and evaluated and evaluated one against the other. And what I'm really complaining about there is that I didn't see that. What I saw was every -- every bid was analyzed as if it was a must-take bid. And there was no -- there was no an-- analyzing, well, is this -- is this other bid better for us that's not a must-take? That's what --

Q. Still having a fixed price?

A. Well, it could be a fixed price. It could be an index price. If what -- here is another distinction that -- what the Company, I know, was not interested in was getting what was called a market price. Okay. We get the -- we pay so much for the capacity and then you'll sell the energy to us at market price. And that extreme, I believe they got some bids that were like that.

Q. For the 2001 RFP?

A. Right. And they were not interested in bids like that because they don't get a hedge against -- against the market price. They get the capacity, and by the way they get it fairly cheap, but then they are at risk to have to pay market price for the energy.

Would they -- and that's a risk that has to do with whether they have a generator go down, whether they -- you know, those types of things, because they are really needing reserves for capacity side. But then they've got an energy risk.

So they weren't interested -- from a risk standpoint, they weren't interested in those that -- that would charge you the market price for energy, so -- but the extremes aren't fixed price, market price. There are index prices. There are -- I mean, there are a lot of options between those two that in some sense share some of that risk.

And if what you're asking me is given the options that you put in, will that affect the cost that's bid, my answer is yes, absolutely. But then -- but then you go through and you evaluate and you say, Out of these options, all of these options that are bid, which is the best for Ameren. And my real objection, I think, is that I didn't see that kind of analysis of various options occurring.

Q. Well, the -- the RFP -- do you have -- by chance have a copy of the RFP handy?

A. I have one upstairs in my files.

Q. I think I have it here. Didn't it ask for a fixed price product?

A. I believe it did.

Q. And was that -- you reviewed the RFP before it went out. Correct?

A. Yes.

Q. And was that language acceptable to you, that the Company was seeking a fixed price product?

A. Yes. And I think the Company and I had some misunderstanding about the initial RFP, because they -- they felt the initial RFP was also asking for a must-take product. And I didn't -- that was not my reading of the initial RFP. And we've -- but that was their reading of it.

Q. Okay. I'm getting toward the end.

Let me ask you some questions about the AEG combustion turbines that you used as a proxy in developing your normalized costs.

A. Okay.

Q. Do you know the fuel used by these?

A. Natural gas.

Q. Okay. And would you turn, please, to page 23, line 4?

A. Yes.

Q. You indicate there that nonfuel O&M expenses of $2.45 per kW should be added to the installed cost of the 500 megawatts corresponding to these AEG units?

A. It should be added as a fixed expense.

Q. Okay. And if I understood what you said earlier, Mr. Bender plugged this figure into his analysis for the twelve months of the test year?

A. No. Actually, Mr. Bender put in 500 megawatts of peaking capacity. He had a -- he had a specified heat rate for those. I think it's shown on page 22, and I'm not going to say what it is because I think it's highly confidential.

Q. Okay. Thank you.

A. And he also had a fuel price, natural gas fuel price, that went with that heat rate, and that's what he dealt with. This $2.45 is fixed O&M expense. It doesn't include natural gas.

I gave this number to Greg Meyer and he put it into the case --

Q. Okay.

A. -- as a nonfuel O&M production expense.

Line 12, I think, in my testimony explains that.

Q. At line 12 you indicate that the $1.225 million figure should be added for the update period?

A. Right.

Q. What's your understanding as to what the update period was?

A. Twelve months ending September 30th, 2001.

Q. Okay. So that's what -- that's what you meant by the update period as reflected on line 13?

A. Yes.

Q. The twelve months ending September 30, 2001?

A. Correct.

Q. Do you know the source of the -- well, you indicate at line 5 that the source of the $2.45 figure is a normalized expense based on moneys spent by UE over the past five years?

A. That's correct.

Q. So in developing this number, you -- the period over which you developed a normalized figure was -- wait. I'm sorry. You say past few years.

A. Few years.

Q. How many -- how many is "few"?

A. If you look on schedule -- this is schedule 5. And I apologize. The work papers that I gave you this morning deal directly with this. And let's see if I can explain this.

There are an average for the last four -- you're going to love this -- three-year averages. It's -- I did a three-year moving average, okay, and that's what's showing up on there. And then I averaged the last four years of that. That little concept of a moving average is try -- is to try to smooth out the cyclical types of things that are showing up in the cost.

So the database actually went from 1990 through the year 2000. So, for example, on schedule 5, 1992, the numbers that are shown there are the first three-year average, so it would have been the average of '90, '91, and '92. Okay. And then the '93 numbers are the average of '91, '92, and '93.

So all of the numbers showing up on this schedule that's titled, "Three-year Averages" is -- are those. And what I've calculated there was -- in the last four years of this, of these three-year averages, I calculated that average and came up with the $2.45 kW.

I also checked -- as you look below, I also checked five-year averages, and looked at those, and they were somewhat lower. And so I went with the -- with the three-year averages.

Q. So the source of this data is the expenses that UE made for its combustion turbines over the last --

A. Yes. It's fixed O&M expenses, yeah.

Q. Now, do you know which -- do you know what fuel is used by these UE combustion turbines that you looked at?

A. Yeah. All -- I'm trying to -- most of them use natural gas. I don't know if there are -- I'd have to go back to see if there are any that use fuel oil.

Q. Okay.

A. But I think all of them do use natural gas. I think --

Q. Okay.

A. I don't -- I think fuel oil was the substitute fuel that was available at the Venice plant, but I'm not sure it was -- I'm not sure that it was available -- I don't think it was available to run the combustion turbines. I don't know.

Q. Well, let me ask you this: To have an apples-to-apples comparison, and assuming the Commission agrees with you as to the use of the AEG units as a proxy, would you agree that it would be appropriate to use data from these gas-fired units to calculate their fixed production costs?

A. That may be problematic because of the short period of time that they've been on line. And I don't object to looking into those, but if -- if they have very high fixed O&Ms, I would want to know why. If they had very low fixed O&Ms, I would want to know why.

As you looked -- as I looked at these numbers, it was very clear to me that a lot of the maintenance that occurs on these units occurs in cycles. I wasn't -- I didn't have -- let me think.

I had -- from the FERC form 1 data summarized, so I didn't have it unit by unit, and I didn't go back and check to see was this particular unit down for a certain type of maintenance that's done every so many years or so many hours. With combustion turbines, it's my understanding it's ever so many hours of operation that maintenance is done.

But it was clearly cyclical, and so I would be very concerned if I've only got one year of data on these plants to be looking at.

Q. Okay. Let me ask you this: Do you know whether natural gas is more expensive than oil?

A. Depends. Depe-- depends on what's going on in the market.

Q. Given -- for the update period as you've defined it, do you know whether gas was more expensive?

A. No, I don't, because I -- again, I did not look at gas prices or oil prices as a part of this filing. I think Mr. Bender and some of the, accountants, Mr. Cassidy, looked at some of those things.

Q. Let me ask you to make an assumption.

Assume, if you will, that natural gas is more expensive -- was more expensive for the update period as you've defined it.

A. Okay.

Q. Now, to the extent that the data -- well, the -- with that assumption, with gas being cheaper, the gas-fired units are going to be dispatched in the economic dispatch order sooner than you would dispatch the oil-fired units. Correct?

A. Correct.

Q. So the gas-fired units would have more production -- fixed production expenses than would the oil-fired units. Correct?

A. I'm not sure. If they are fixed, they don't vary with the operation by definition, so I guess my answer would be no, I don't think so.

Q. Okay. Well, in the economic dispatch order, again, assuming gas is cheaper, you're going to be running the gas units more often than you're going to be running the oil-fired units?

A. If gas is -- this -- let's put -- here's -- here's my understanding of what happens is, you run the unit, okay, because you need to run the unit, and you make a decision at that time which of the two fuels is cheaper to use, the gas or the oil.

I don't -- I don't know that Union Electric is restricted to a fuel -- units that are just oil-fired or units that are just gas-fired, but I would run a unit on oil because that's the cheapest that's available.

Q. Well, these --

A. Not that I've got a set of units that are oil-fired and another set that are gas-fired, particularly, in the combustion turbines.

My assumption is that they were all gas-fired, but there might be times when they run them on oil because oil was a cheaper fuel than natural gas at that time.

Another possibility is that in the winter they may run them on oil because the natural gas is not available. I don't know.

Q. Okay. The AEG units that you used as a proxy --

A. Yes.

Q. -- is it your understanding that they are dual fueled, or do you know?

A. I don't know. My assumption is that they would run on natural gas, and that's the way that they were put into the -- into the fuel model.

Q. Your understanding is that they are -- that they use natural gas --

A. That's correct.

Q. -- only? Okay.

A. I think --

Q. Go ahead.

A. I'm not sure whether -- I didn't get into -- I did not get into the details of whether those units were dual fuel or could be fueled by natural gas or -- or oil, or if there is some additional cost that's --

that's incurred to make a unit dual fueled.

We just assumed that they were fueled by natural gas, and that's the way they were put into the fuel model.

Q. And it's your assumption that the UE data that you looked at with the -- with -- and the three-year averages and so forth that you derived, that that data pertained -- the source of that data was gas-fired --

A. Combustion turbines.

Q. -- combustion turbines in operation at UE?

A. Yes.

Q. Are you familiar with the Environmental Protection Agency's New Source Review Standards?

A. No.

Q. Are you aware of any EPA regulations which might impact new gas-fired combustion turbines?

A. No.

Q. Okay. One more topic.

A. Okay.

Q. As a matter of policy, would you agree that the standard for reviewing whether a utility was reasonable in a resource planning decision should be based on the conditions at the time the decision was made?

A. Yes.
Q. And would you agree it should not be based on hindsight review?
A. I agree.
Q. And would you agree that one factor in determining whether a utility was reasonable in its resource planning decision would be whether the utility complied with Commission-approved resource planning standards?
A. That would be a necessary condition, yes.
Q. Okay. And a factor that the Commission would look at --
A. Yes.
Q. -- in determining the reasonableness of that decision?
A. That's correct.
Q. I think you would agree with the principle that regulation is designed to be a substitute for competition, or would you?
A. Ideally, that -- that's the goal.
Q. Okay. And so doesn't it follow from that that if you have competition, that regulation is not necessary?
A. If you have -- I'm trying to figure the -- bring to mind the right adjective to put in front of

competition, but -- robust competition, I'll use that, then I agree.

MR. RAYBUCK: Okay. Dr. Proctor, thank you very much.

I have no other questions.

(PRESENTMENT WAIVED; SIGNATURE REQUESTED.)

____
MICHAEL S. PROCTOR, Ph.D.

Subscribed and sworn to before me this day of , 2002.

____
Notary Public in and
for County,
State of Missouri

C E R T I F I C A T E

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

I, KRISTAL R. MURPHY, CSR, RPR, CCR, with the firm of Associated Court Reporters, do hereby certify that pursuant to agreement, there came before me,

MICHAEL S. PROCTOR, Ph.D.,

at the Missouri Public Service Commission, Room 210, Governor State Office Building, in the City of Jefferson, County of Cole, State of Missouri, on the 17th day of April, 2002, who was first duly sworn to testify to the whole truth of his knowledge concerning the matter in controversy aforesaid; that he was examined and his examination was then and there written in machine shorthand by me and afterwards typed under my supervision, and is fully and correctly set forth in the foregoing 169 pages; and the witness and counsel waived presentment of this deposition to the witness, by me, and that the signature may be acknowledged by another notary public, and the deposition is now herewith returned.

I further certify that I am neither attorney or counsel for, nor related to, nor employed by, any of the parties to this action in which this deposition is taken; and further, that I am not a relative or employee of any attorney or counsel employed by the parties hereto, or financially interested in this action.

Given at my office in the City of Jefferson, State of Missouri, this 18th day of April, 2002.

KRISTAL R. MURPHY, CSR, RPR, CCR

COSTS: (Computation of court costs based on payment within 30 days.)