# CASE NUMBER:

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the early `90s up until about 1997 Delta was trying to avoid a rate proceeding, if it could, to avoid the expense. It was looking at other alternatives to improve its financial condition?

A Yes.

Q Okay. And you would also agree that the experimental Regulation Plan in some extent--to some extent will adjust rates annually, one way or the other, within the confines of the alternative regulation proposal?

A Yes.

Q What change in management--or what brought about the change in management philosophy that moved from trying to avoid a rate adjustment to looking at one of some type of annual adjustment?

A Well, the--from--I think we had a case in `85 and a case in `90, and both of those really started back in 1985. We had four cases in five years from `81 to `85. And very expensive and time consuming and we started then to say are there, you know, what can we do and we were in a growing service area and picking up a lot of new customers, and industrial parks were being developed and adding industrial load, and we said let's every year try our best to not file a rate case instead of the other way around of always filing. And that's what we did from `85 to `90, and we did it from `90 to `96. We also, during that time, had a lot higher retained earnings than we do now. We had earned our dividend more years and we had some years when the weather was much colder and we had some good years and we were able to, to some extent, if you want to say that, operate off the retained earnings. Those are gone now, we have depleted our retained earnings, we haven't earned our dividend in four of the last five years and we serve a rural growing service area that demands more and more capital just to keep up with the growth in eight or ten of those counties. And we don't see a future way to continue to do that absent some means of trying to stay more current. And that's what all those things have led to, to where we are today, not any one in particular but all of them.

Q Okay. Let me follow on that theme. Would you agree that it is Delta's position anyway that the cost control measures that are in the proposed Alternative Regulation Plan will encourage Delta to control the growth of O&M expenses?

A I'm trying to remember without looking at it, it is--the band on O&M, well, it encourages us to control O&M on a per customer basis and penalizes us if we don't. So, I think the answer is yes, it would encourage us to and would penalize us if we cannot, and it would provide us some incentive if we can.

Q We could agree that it is also Delta's position that as the plan takes effect and these cost control measures begin to work, that costs will decrease as a result of the incentive and that, as a result, Delta's customers will benefit from the decrease?

A They will either decrease or I think be controlled within the band. I think either way there will either be a control or reduction. Control doesn't mean it is always going to go down, but it will be controlled within a band.

Q Okay. Now, as to the cost control measures. The Commission asked what written procedures, internal guidelines were available dealing with cost control measures and the response from Delta was that there were no written procedures or guidelines or internal standards. And, if you wish, I'm speaking concerning Delta's response to Item 21 of the Commission's Order of June 4, 1999.

A I probably should look at that, if you will give me just a moment while I find it.

MR. WATT:

Item 21 of June 4, is that what you said Jerry?

MR. WUETCHER:

Yes, sir.

Q And let me clarify, that is from the Alt Reg case, 99-046.

A Okay. I have familiarized myself with that now.

Q So, is it correct to read from that statement that there are no written procedures

concerning cost controls?
A That is correct, there are no written procedures, as such, regarding cost control.
Q All right. Now, in light of the fact there aren't any written procedures, how will Delta implement cost of service improvements that it has been talking about that will result from the implementation of the experimental plan, if there are no cost control procedures?
A Well, I didn't say there weren't any cost control procedures, I said there weren't any written ones.
Q All right, let's--
A I didn't elaborate because I've been trying to answer your questions.
Q I appreciate that. In the absence of any written procedures--
A Okay.
Q --how will Delta be able to implement those cost controls?
A Well, I'll go back to where we started at 9:15 this morning on the budgetary process, because that is sort of what this question relates to.

That is where we control. When we annually--

CHAIRMAN HELTON:

Mr. Jennings.

A I'm sorry.

CHAIRMAN HELTON:

We are all familiar with that, I think the question is no written procedures. Mr. Wuetcher may need to rephrase his question, how will this Commission or any of the intervenors know that you are actually implementing cost control?

A I'm sorry, I misinterpreted the question, I thought he meant how will the company manage to do it, wasn't that the question?

CHAIRMAN HELTON:

That's what he asked but I'm asking--

A Oh, I'm sorry.

CHAIRMAN HELTON:

--how would anybody else know if you don't have any written procedures?

A Well, because we don't feel like we need written procedures. And our company being a very small company with only four or five officers and we meet weekly and we meet with all the management people regularly, we communicate verbally. You know, I communicate to people about controlling cost and I go through and view every account when we are budgeting and I feel very comfortable that we eliminate any unnecessary expenses in that process, and we do that annually, and we follow up monthly to see how we are doing. And we have never felt the need to write that down to say that is what we are going to do because we communicate and do it.

CHAIRMAN HELTON:

But you weren't under an environment where your--a new mechanism either.

A But we would still do it the same way, I guess. If there is a strong need, if someone feels that we need to write down what I just said, we can do that. But, you know, I don't have a problem with it, I just--I've tried to avoid written things and deal with people more directly all the time.

Q Well, let me follow up on that, does Delta do any type of comparison of its O&M costs with other gas systems to evaluate its cost containment efforts or budgetary efforts?

A We have compared, more compared ourselves through--we have some performance indicators that came out of the management audit that compare a lot of different categories and some of those are to other companies and some are to ourselves internally over, say, a five year period. And so, those do help us to measure how we are performing over time compared to ourself and, like I say, in some areas, to other companies. Could I--
Q Let me go ahead and ask a couple of more on that.
A I just wasn't sure I was finished on that answer, but--
Q Well, if you are not, I'm sure we will get back to it in just a second.
A Okay.
Q When you say that you compare to--what measures are you talking about and to what other utilities are you comparing?
A Well, you see that's what I was going to finish elaborating on.
Q Okay.
A There are not a lot of companies, particularly in this state, that are like Delta Gas, 21 county

rural service area, 2100 miles of pipe, you know, scattered all over the place, a lot of them are more focused. And it is not easy to compare apples to apples when you are doing those comparisons, okay. It's very difficult. And there is not a lot of companies in the country that are that similar in terms of operation, you know, we are fairly unique in many respects. So, that is something that is a real struggle. But in the management audit, with the performance measures that we are requested to develop and put in place, we have those things that we think can be compared and some of them are expense things and some are gas supply items and different ways that we can try compare ourselves to other people, and we do that. We do it on an annual basis, we share it with our management team, we do it before we develop our budgets, we share it with our Board of Directors, and I go through that whole process.

Q Could you provide us a list or a set of comparisons that you've made?

A Yes, I could.

Q Let's say we take the last three years, just to show what your target group is and how you compare it?

A I can do that, because each year that we do it we do three or four years and we just roll a year out and a year in. So, even the most recent one which was in the spring was looking at, like, a three or four year time frame.

Q And those comparisons will indicate the utilities that you are using as your benchmark?

A For the ones where we are using other utilities, or it will indicate it is comparing Delta to itself. We found it very useful, as we make changes, to compare ourself year to year to see how the changes we make affect the various costs. And it is capital, construction, operations, gas supply, a lot of different areas.

Q Just a couple more questions. I want to get back for a moment to the issue of equity distress that Dr. Blake had mentioned and we had touched upon earlier. Would it be correct to say that part of the problems that Delta--or the stress that Delta is currently

experiencing is in part the result of its efforts to expand customer service in its service territory?
A Yes.
Q Okay. And would it be correct to say that, to characterize some of your policies that promote growth, that they are much more advantageous than, perhaps, other utilities are?
A Advantageous to whom?
Q Well, lest me go ahead and clarify that. Would you--it is correct that--is it correct that Delta installs the service line at no charge for its residential customers?
A Up to a certain amount.
Q Okay. And is it not correct that Delta had to obtain a deviation from the Commission's Regulations in order to do that?
A Yes, I believe maybe 1989 we had a proceeding here, but I don't think we are the only utility in the state that does that. I think Columbia did it before we did and we sort of tailored ours after what they had done.
Q Okay, and--

A There is a reason for that, by the way.
Q Well?
A If you don't want to know it, that's fine.
Q I'm sure somebody else will be asking about it.
A Okay, all right.
Q The other area, Delta also has a main extension policy that provides 200 feet of main extension before the customer is charged?
A Up to 200 feet.
Q Up to 200 feet?
A Yes.
Q And that is roughly twice what is required under the Commission's Regulations?
A Regulation, as I understand it, requires up to 100 feet upon request and we stand to provide up to 200 feet upon request.
Q And that is in part--the reason part of that is in order to promote growth and make the extension service more attractive within your service area?
A I would say it is more of a necessity in our service area because of the nature of our

service area. Being very rural and spread out with bands of, you know, unserved areas and where the growth is developing, it is very difficult to get gas supply to people.

Q To the extent a customer has to pay for a 100 feet when he can get that extra 100 feet for free it, is more an incentive for them to take service, though, isn't it, at least the disincentive for not taking service is not as great?

A I would agree with you, I just disagree with the word free, because it is in rates, so, I mean, okay, I mean it is recovered, it is just like the service line issue, it is an immediate recovery or longer term recovery.

Q Okay.

A The customer either puts in the service line or we do and it is either long-term in rates or it is an immediate thing if they put the service line in immediately, it is the same way with extensions.

Q And just to follow up on that with one more question on that issue, and that is again a management policy in order to promote Delta's

position in the area and to expand service?
A I can't agree with that statement but it is a management decision, yes, but it is not just for what you said. It is also to be able to get gas to people that want it.
Q Okay.
A And we think in the least costly, most efficient way to them. That is the way we view it.
Q All right. Are you aware that some utilities will issue debt and common stock to maintain its desired equity to debt ratio?
A Yes, sir.
Q And could you explain why Delta does not do that or has not done that when it has issued large debt?
A Well, we have. And we issue common stock and debt both, so we have done that.
Q The last time that there was a large issuance of debt did--was there an accompanying issuance of common stock?
A There was not, but that is the case many times where we will issue common stock or debt, sometimes both, sometimes only one, it

depends on the market, depends on the investment bankers, depends on the company needs. It can be one, it can be both, it can be just equity or just debt. But that is very common in the industry, that is not just Delta.

Q When was the last time that Delta had a large issuance of common stock to correct its or at least to bring its debt in balance?

A We brought along our Annual Report, I'll look it up in there so I don't give you the wrong date.

Q Well, if you can just give me a ball park year that would be fine.

A July, 1996, we issued 15 million of debentures and 400,000 shares of common stock. So, that was--that would have been our last equity and debt offering. And then in 1998 we issued 25 million of debentures. Part of that was to refund and repay some existing debt to get better rates and part of it was to pay off short term.

Q When--I think in some of the responses to the information request it was indicated that the imbalance began to occur back in around

1990--1988-`89 time frame, were there any accompanying issuances of stock then or were they even considered?

A Let me explain and--because I can't remember, okay, specifically that year, so let me just explain in general how it works.

Q Well, in order to--I'm not going to tie you to a specific year because that would be unfair, you have already said that year--but within that time frame of, let's say, 1988 through `92, `93, was there any issuance of stock or should I just refer--

A Well--

Q I'll tell you what, we will just refer to the report in order to save time.

A Well, I brought--I brought an old report to try to cover some years, let's see if I have enough. In 1993 we issued 15 million debentures and 170,000 shares of common stock. In May of 1991 we issued 10 million of debentures, so that's a couple of financings we have had. The way Delta's business operates is we function on a credit line, that's a 25 million dollar line right now, and periodically we have to refinance that as it builds up. If we don't, the banks cut us off. They won't, you know, continue to extend credit. And so, we have been financing every two or three years with debt or equity. And we try to do that--we shoot to maintain about a 50/50 debt to equity structure on the long-term, but in the short-term it can vary from that. It depends on our needs, it depends on the financial markets, depends on where the stock pricing is, whether the investment bankers want to do an equity offering for us, so it is affected by a lot of things, some of which are outside of our control. And over the last ten years that is what has happened, over the last 20 years that I've been at Delta that is the way we have operated. We have historically refinanced that short-term debt from time to time and sometimes we refinance outstanding long-term debt with better term debt if the markets are such, you know, if interest rates drop, that sort of thing. That's the way we go about doing it and that is what we have been doing it, and we find ourselves at times heavier in debt or heavier in equity depending on the markets and what we run into.

CHAIRMAN HELTON:

Mr. Wuetcher, do you want--is that report not in any data request and do you want it entered?

MR. WUETCHER:

I think that may be in it, if it is not, I believe it is on file with the Commission.

CHAIRMAN HELTON:

Okay, fine.

MR. WUETCHER:

I think that is all we have. Thank you Mr. Jennings.

CHAIRMAN HELTON:

Commissioner Holmes? Commissioner Gillis?

MR. GILLIS:

I'll wait until after the Attorney General has some questions.

MS. BLACKFORD:

I have just a couple I want to follow up on.

RECROSS EXAMINATION

BY MS. BLACKFORD:

Q Am I correct that Delta increased its dividends from $1.12 to $1.14 in 1997?

A Is that calendar or fiscal `97?

Q Calendar?

A Calendar `97, I'm not sure that is correct. The Annual Report shows that our dividends for fiscal `96 was $1.12 and for fiscal `97 was $1.14. Now, I don't know the exact time but somewhere in there we increased it a little bit. I'm not sure which year that fell into is the only reason I asked.

Q Why did Delta increase its dividends when earnings per share were greater than the dividends per share only once since 1993?

A There is a significant pressure on a public company to raise equity capital. One of the considerations is the level of the dividend, the yield. The other is the investors expectations on where the price is going to go. In other words, as they evaluate it, and investment bankers as they look at selling equity for you, they look at what the demand is from their customers. And in the industry over the last 10 or 15 years, most LDCs like Delta or larger, for the most part larger, have been increasing their dividends in the 2% to 3% range. There is a lot of pressure on a company that is trying to sell equity and compete with all the other people who are selling equity to be providing some return that is similar or some dividend that is similar and some dividend growth over time. So, Delta has always tried to maintain its dividend where it had it and over time to try to gradually increase that to be competitive on raising equity capital. And that is why-- in `96 I show that we had earnings of $1.41 that year and our dividend is a $1.12. And we decided then to increase it very slightly to two cents on a $1.12 dividend to give the market some understanding that we had a dividend we could maintain and perhaps, you know, could continue to increase over time if earnings were there. And that's why we did that, just to try to react to the requirements of the market place.

Q So, would I correctly characterize this as a management decision to, in the face of potential lowering, to actually exacerbate the problem of having earnings insufficient to meet your dividend?

A Yes, you could say that, but we didn't anticipate that the next three years after that we weren't going to earn the dividend. I mean, that is the other side of the coin. We always anticipated earning our return in the future and we weren't able to, but, yes, to answer your question.

Q In that period of 1991 to 1995, where there was no rate case, am I correct in understanding that the borrowee for `92 was over 15%?

A For fiscal `92 it was 15.1 is what I have.

Q Fiscal `92--

A That's June 30, that's using the annual.

Q And for fiscal `93 was it 15%?

A 14.9.

Q For fiscal `94 was it around 12%?

A Yes, 12.05 I have.

Q Was that attributed in any way to Delta's decision not to file rate cases during that time?

A Of course. Each year that we look at where we are and project where we are going, you know, if we don't feel like we need to adjust we don't. We had been allowed during that time, as I recall, a 15% return on equity. Or that had been in our last case that came through the Commission and it had not been changed since that. So, we--and this is consolidated results as well, but we were not earning more than what had been allowed, but we were earning enough to where we didn't feel like we needed to come in for a rate. Now, the weather during some of those time periods was also a factor, you know. We had, if I might just flip to that, we had--well, for instance, it ran `93 was right at normal weather, `94 was 6% colder than normal, so there was some times in there when some of those things occurred where weather was a factor.

Q Well, that brings up something very important, if the weather normalization adjustment factor, as you proposed it, goes into place the allowed return and the actual return will essentially track one another with reference to the weather conditions; is that true?

A With respect to adjusting the normal weather that is correct.

Q And one of your major problems historically, as you have posed it here, has been that the company has been brow beaten by bad weather; is that correct?

A Well, it has been both ways. I mean, we have had years when we earned well when it was colder and we have had years when we didn't earn as much when it was warmer, because our sales are weather sensitive on residential and commercial sales.

Q Surely. But do I not understand testimony from you and from others that bad temperature years from the natural gas company point of view have, unfortunately, been the norm for the last few years? These have contributed to low actual earnings?

A Well, it has been for--well, let's see the last--`98 was only 94% of normal, `99 was only 89% of normal, so at least for those two. `97 was 104% of normal, it was actually colder than normal, but that was the year of the last rate case as well, so that contributed to that as well, that's why I mentioned that earlier.

Q In the 98% and 89% years would produce lower than expected revenues and reduce your actual rate of return?

A That's correct, everything else being equal, that is very correct.

Q Had the weather normalization adjustment now proposed been in place then would the actual rate of returns been closer to, if not equal to, the allowed rate of return?

A I would say they would have been closer to, I'm not sure they would have been equal to because there are other factors that affect earnings other than just weather, but everything else being equal it would have helped. And either way it would have adjusted up or down.

Q Now, you pointed out that the weather normalization clause would also operate to lower the company's return in cold years, am I correct?

A Could you repeat that, I'm--

Q In below degree--I may be saying this backwards. In a year that is, from a natural gas company's point of view, beneficially cold--

A Colder than normal.

Q Colder than normal. It would operate to lower the revenues the company receives during that time from what they would have received had there been no weather normalization adjustment?

A Yes, it would always function to bring the impacts of weather back to 30-year normal weather. And to the extent that that is changing, if you are in a warming trend, I mean, you can have some impacts from that either way, or colder trend for, say, the last ten, but everything else being equal it would tend to bring you back closer to that. But that is all that a rate case does anyway is try to normalize your weather for normal weather. I mean, that is the way they have always been done so that is no different than--

Q They have always been done to normalize it for purposes of establishing the rate, they have not been done for the purposes of insuring that the revenues match the established rate, isn't that correct?

A But the whole underlying tenant is that they will, otherwise, the whole process is a fallacy. If they don't try to match up to normal weather over time, then the whole thing doesn't work, you know, for the company or the customers. So, I think underlying it is the fact that it does work, at least from the way we view it. You just have the short-term impacts one way or the other. Any year can be colder or warmer than that 30-year average and we can't predict that. So, sometimes it is one way, sometimes it is another way.

Q Well, perhaps we are having two different conversations and not intending to do so.

A I'm sorry.

Q I'm trying to establish what the benefit of the weather normalization adjustment factor is. And what I'm hearing from you in that last answer is that there is none.

A The benefit to whom?

Q To the company?

A To the company.

Q To the company which has sought it?

A Because there is two benefits, there is a benefit to the customer as well, that's why I want to point that out. I mean, if you do not have weather normalization and the weather is warmer than normal. then you will adjust up to the 30-year average. If it is the other way, you will adjust down. But without it, you know, it cuts both ways.

Q Certainly.

A So, there is an impact on both the customer and the company I guess is the point I was trying to make.

Q So I'm looking at it from the utility's point of view, what is the benefit to the utility of the weather normalization?

A Well, again, to the extent that our rates were set in a rate case that assumes normal weather, then the underlying rates are set assuming that that is going to take place. Now, if, in fact, that does not take place and it is either warmer or colder, then the rates will be adjusted and the utility will have those rates to reflect those volumes being either warmer or colder than normal. That's the impact on the utility.

Q So, the net result is that you actually more accurately tracks your allowed rate?

A Yes.

Q And that is a benefit to a company which has suffered from years that are warmer than normal and, therefore, have not had actual revenues to match the allowed rate?

A It is and it is a detriment if it is colder than normal. So, it is a two edged sword.

Q Well, now, let's talk about the arc, it also acts as a leveling influence, it has an up side and a down side as I see it, so could not the same benefits and drawbacks be assigned to the arc?

A The alternative regulatory approach, I'm not sure I understand what you mean by the benefits in that, but it will function to maintain within the confines of what it is, the controls and the target return, to help provide the opportunity to earn that.

Q It will essentially bring the allowed rate and the actual rate in line regardless of what happens with weather?

A Or at least closer together.

Q Just as the weather normalization clause does, they both adjust for certain factors--

A That's true.

Q --and by doing so, bring those two items closer together, meaning that they increase it during warmer than normal years and decrease it, perhaps, during colder than normal years or maybe not?

A Well, not perhaps, I think they both would tend to decrease it when it is colder and increase it when it is warmer.

Q Is there a benefit independent of that that is provided by the weather normalization adjustment clause attending--that attends the Alternative Regulation Plan from the utility's point of view?

A I'm sorry, could you ask me that again, somehow I just couldn't grasp the question in that.

Q Is there a benefit the utility will receive from the Alternative Regulation Plan that is not also received from a weather normalization adjustment factor?

A Well, I guess the weather normalization only addressed weather and the alternative regulatory approach the benefit, I guess, is two fold, one--and this is just not the utility benefit but it is streamlining the cost saving aspect of not having to file rate cases all the time. And, also, within the target, within the band, you know, if you can control cost, then the utility will share in those it controls or it will have to have a detriment on those that it doesn't, so, I mean, it is a two edged sword on both. So, the Alt Reg is a bit different than weather normalization, I think, because it has some features in it beyond just weather.

Q So, you are saying that there would be no effort to streamline expenses or to do those other beneficial things if there were only a weather normalization adjustment?

A No, I'm not saying that. I don't think I said that at all. You just asked me the difference between the two and I responded.
Q Is there not in conjunction with the weather normalization an effort to streamline and would there not be benefits to the utility from that?
A Well, there are--our position is that we always try to operate as efficiently as we can.
Q I certainly understand that.
A So, we will continue in that. The whole idea behind having, I think, performance measures, and I think maybe that is what the Commission and other companies have considered here in this state and in other states, is to provide incentive for that and they have found that the incentives tend to help promote that. And to the extent they don't, then the detriment helps the other side of it, the penalties end up helping that to happen. So, we decided to put some of those things in what we filed for to try to encourage that.
Q I was a little curious, you were asked at one

point about the AAF and the operation of the performance based controls, if I could paraphrase your answer, and please tell me if I'm paraphrasing it as something other than what it was, you said I'll have to think about that, I have to remember exactly what is in there. And you had to pause a moment and think before you could answer the question, is that correct? Does that match your memory of what happened?

A Except I don't remember it in the context of the AFF, it was more a question just about--what do you mean when you say AAF, what does that mean to you?

Q Well, my understanding is that the performance based mechanisms of this alternative proposal fall within the AAF factor, that they are applied to what ultimately constitutes AAF?

A Could you just clarify for me what you mean by AAF, just so I can focus myself?

Q The historic factor that is applied in the year after the first year has been in place in order to adjust a budgeted--in the

original proposal, budgeted to actual?
A That's the first year after the--okay, all right, I'm with you now. All right, what was your question?
Q All right. The question was that you had--the question was you had to pause and think about it; is that correct?
A Well, he didn't--as I recall, it was Mr. Wuetcher and he didn't ask me about the AAF particularly, just the whole concept. And I paused to think about those things that are in the whole alternative regulatory approach that we have. And some of those might be in the AAF, some might be in the--what's the other term--
CHAIRMAN HELTON:
AAC.
A --AAC because there is the equity test, there is the O&M test and then there is the 5% test, so I'm not sure which piece those fall in but that is why I stopped to just think through the pieces of it.
Q Now, am I correct that you have been instrumental in choosing the method to be

developed and in helping develop this method for the last year?

A Yes, particularly the overall idea of it, the overall concept of it.

Q But you still find it very confusing to figure out what goes where and when?

A No. I told him I could get them out and compare them. I've been through 12 volumes of data in the last two days and to say that I would remember every detail of that without looking--I said I'd be glad to get them out and compare them if he wanted me to, that I could do that, and I could do it for you if you would like for me to.

Q Well, actually, all I'm talking about is what are the simple components of the three factors?

A Okay.

Q It appears that you are having some difficulty remembering which components go with what factors?

A No, I don't think I am. If you'd like for me to get them out and compare them right now I'd be glad to go through them with you, I have no problem with that.

MR. WATT:

Your Honor, let me object to this line of questions. I believe that the components of the three factors are explicitly set forth in the plan as submitted. And it really doesn't seem to me to serve a lot of purpose to subject Mr. Jennings to a memory test as to what he remembers being where.

CHAIRMAN HELTON:

I think, Ms. Blackford, that was your concluding question on that anyway, wasn't it?

MS. BLACKFORD:

It certainly was.

Q Let me ask you also about the fact that you indicated that you thought rate case expenses which have been burdensome to both Delta and its customers would--general rate case expenses--be abated were the alternative rate plan placed into an experimental three-year life? Have I correctly said what you were claiming as a benefit?

A Yes, ma'am.
Q Let me ask you, is the O&M expense that becomes the basis to which the Alternative Rate Plan factors are ultimately applied, that O&M expense which will be established either as a part of this rate case or if none is established as a part of this rate case, that which was established as a part of the last rate case, 97-066?
A I think it would really be established in this rate case.
Q In all likelihood?
A Yes, it should be.
Q And that is then the O&M expenses to which all the multiples are applied?
A Yes, because you have to have a starting point.
Q And that starting point would include in it, would it not, the full rate case expense from this rate case being amortized, or the amortized rate case expense from this rate case; am I correct?
A Yes, it would include some portion of it, I'm not sure exactly how much.

Q And I believe that you have also included in your miscellaneous expenses, which are part of your O&M, what remains from the last rate case that has not yet been recovered through amortization?

A No, because it is being spread over a multiple period of years, that's correct, and its an annual amount.

Q And so, those would be a part of that 100% O&M to which factors have been applied, right?

A Yes.

Q So, they carry forward and are continued to be a part of the rate structure and the expense borne by the customer regardless of whether rate cases continue as general rate cases or not; is that right?

A Well, until they are amortized out, I mean, it is like any amortization, it has--you know, if you have a rate case and you have a number that is spread over three years if you don't continue to spread it over three years you don't recover it.  If you have an order that allows, you know, a three year recovery, then you have to continue to do that until it is amortized out, otherwise there is a fallacy in the whole discussion on amortization.

Q But they still remain a part of that base rate, regardless of whether they are amortized out, to which the multiplier is applied?

A Yes, over the--I guess over the--probably over the three year term of the Alt Reg it would. Another--that's another reason to make it a three year program because then you, you know, by that time you have worked your way through those things and then you would reestablish or move forward.

Q Now, you are saying we reestablish them, where in the proceeding do I find any suggestion that there will actually be a reestablishment of O&M rates?

A Well, because at the end of the three year experimental period the Commission has to, and staff and intervenors, have to reconsider Alt Reg and either continue it, modify it or discontinue it. It doesn't continue on its own merits, it is a three year program. Like in Alabama is the way we consider it, you have to either reup it, modify it, or stop it and go back to traditional regulations at that point.

Q But if you simply reup it, the base rates continue as they were in the original; is that correct?

A That depends. I mean, I can't dictate the terms on which it would be reuped. If it were reuped exactly as is you are correct but, you know, I can't forecast that. I don't know what that will be.

Q But there is nothing in this proceeding that says, in fact, this is what we propose, that it be examined on this basis and that these adjustments be made at that time?

A That time being now or three years out?

Q At the expiration of the three year period?

A Oh. Correct, but there is nothing that says they can't. Those things just weren't really addressed.

Q Certainly, during the initial life of this particular alternative regulation mechanism it is a part of the expense to which the multiplier will be applied?

A Yes, that's correct, because it is an expense, it is an O&M expense.

Q You also pointed out the fact that as a benefit that there could be possible decreases in rates that attend the Alternative Regulation Plan and I want to explore a little more with you the circumstances on which you think those decreases of rates might occur during this initial three year period. Can you tell me the circumstances under which you foresee that happening?

A That rates might decrease during the period of time? If expenses went down.

Q If expenses went down after they had been subjected to an inflationary rise, if they then went down?

A Or, yes, if we controlled expenses, below some point then there would be a sharing, or if we, you know, if the weather was very cold, you know, different than the 30-year average base sort of thing you are basing it on. I mean, there are things that could lead to rates going down.

Q Now, that rate could go down if it were simply a weather normalization adjustment factor, it would be applied to that very cold year and you were under traditional rate making; is that correct?

A If it was only the weather that was affecting it, yes, because that would just adjust for weather, that's correct.

Q So, a downward trend in the O&M expenses is the only realistic mechanism for any rate reduction during this time period?

A And I believe that is generally correct and I believe that's O&M per customer, I think, not just O&M--

Q What are the circumstances under which you perceive the company earning a rate of return that is higher than the top band proposed by the ARP during this initial three year period?

A Earning a return greater than the top of it, the circumstances I--under which I see them doing that?

Q Which you foresee might lead to such a result?
A I'm not sure I can foresee any.
Q And yet you listed the top of that band as a valuable benefit of this plan during this period of implementation?
A Okay. I guess I--I guess the one thing I'm thinking about is weather. To the extent that it was--I guess I'm also thinking about weather normalization and Alt Reg since we filed for both of them. But if you didn't, if you just had the one and you had an extremely cold time then you could be above it and come back to it.
Q But, again, weather normalization clause or factor might do exactly the same thing?
A Yes, that would adjust for bringing weather back to the 30-year average, that's correct.
Q And in the meantime would stabilize the rates in an upward format were there to be a warmer than normal year?
A Yes.
MS. BLACKFORD:
Thank you. That's all my questions.

CHAIRMAN HELTON:

Mr. Gillis?

COMMISSION GILLIS:

No questions.

CHAIRMAN HELTON:

Mr. Jennings, I have a couple of questions. Recognizing you have a lot of years of experience in this industry, you know a lot of people in the industry, I guess I still was a little confused by why you didn't seem to look at any PBR or other types of PBR plans in other states within this state. And recognizing that Delta is a--serves a different kind of territory and that there are few companies to compare yourself with, give me a succinct answer as to why you did not look at PBRs?

A I think we wanted to look beyond just the PBR concept is pretty much it. We wanted to look to--beyond that to something that would allow us to avoid what we considered to be a very costly effort to have more frequent rate cases and we saw the target return approach, the Alagasco approach, being one that would do that.

CHAIRMAN HELTON:

And why have you not proposed anything to control your gas costs?

A Our position has been that gas costs have traditionally been recovered as incurred, including pipeline capacity and the flowing gas cost. With deregulation of supply, gas is priced pretty much at the market on a national basis, and we have always recovered those costs, especially, in times when they were rising. And our position has been that as prices have leveled or have fallen, we wanted that benefit to pass back to the customer. And we believe that we do control our gas cost as best we possibly can to get the lowest gas price. We have no incentive to have higher gas prices than what we have and, so, we feel like it is the best way to go to let that pass back to the customers, as well. So, we have looked at it and just said we don't think that that is something that is going to benefit and we prefer to stay traditionally the way we have been doing it.

CHAIRMAN HELTON:

Is the plan that you have filed here discussed

with your Board?
A The alternative reg or the weather norm or the whole--we have discussed the alternative regulatory approach with our Board, the weather normalization approach with our Board and the--some of the concerns, you know, about filing a rate case. And we always do that before we file a rate case, we always discuss that with our Board in the context of working on our budgets and to keep them informed and to get their input and to, you know, how they view things.
CHAIRMAN HELTON:
And Mr. Wuetcher asked you about the consultant that you employed and what you asked them to look at. When you selected the CPI-U as an index, was that the--your suggestion or the consultant's suggestion?
A I think it was--I think that was sort of jointly arrived at as we thought about, well, what would be a reasonable thing to use that is obtainable, measurable and you can get at pretty easily and that people really are very familiar with, and we thought that was

probably the best one to use. And I think we probably made that decision jointly, or maybe they concurred with our thought that that was one that would make sense after thinking about other things to use.

CHAIRMAN HELTON:

I guess I'm curious as to why you didn't select the GDPPI versus the CPI-U?

A Well, we thought the CPI was, you know, for us readily obtainable, somewhat understandable and the whole concept within our company, we compare a lot of things to CPI when we look at inflation and that sort of stuff, and it was just a much more meaningful thing for us to use than any other. We don't use the other for anything, not to say that we couldn't look at that but that is the way we arrived at what we did.

CHAIRMAN HELTON:

In the last management audit you said you had implemented all of the efficiency--the efficiencies that were suggested in the management audit.

A Yes.

CHAIRMAN HELTON:

Do I understand that you still have the same number of field offices and service centers and so forth, that you have not, as other companies have done, that you have not consolidated those into smaller numbers?

A Was your question that--you are stating that we do have or are you asking if we do have?

CHAIRMAN HELTON:

I'm asking you.

A We do not, we have consolidated several of those in the management audit, and we down scaled our work force through attrition, primarily, and our employee per customer count is sort of how we measure the field, went down fairly significantly. I think over a two or three year period it was like a 11% or 12% reduction in the early to mid 90s. So, we made a strong effort in implementing those things to operate as efficient as we could.

CHAIRMAN HELTON:

Do you have any redirect?

MR. WATT:

Your Honor, I have just a few redirect.

REDIRECT EXAMINATION

BY MR. WATT:

Q Glenn, when you were asking questions that were posed by Mr. Wuetcher, at one point you responded to a question about the amount of information that is delivered to the Board in connection with its consideration of Delta's budget, and I believe you said you don't like to give them that much information and spread your arms apart. Could you please describe in words what you meant by that as opposed to simply the hand movement?

A Yes. I meant all of the underlying analysis and details that the various people in the company work up, the budget agents and the officers to support the request for budgets. We normally don't provide all of that detail to the Board, it is available and I always tell them it is available if they choose to review it, send them the budget--

CHAIRMAN HELTON:

Mr. Jennings, I think what he asked

required a quantitative answer. Could
you say four foot or--
A Okay, it is--
Q It looked like it was about a three or four foot stack of material; is that fair?
A It's a large stack of paper that is somewhere between a foot and a foot plus.
Q All right. Is it important to Delta that it, as a philosophical matter, that it provide persons in its service area a choice of energy sources?
A It is very important to us. We serve this rural area that in many cases would not have gas service offered to it if we weren't there and its a challenge to do that. And they have only electric service to choose from either the co-ops or KU, LG&E, or other fuel such as propane or oil or coal, and they really want natural gas service. And so, it is very important to us to do that and we view that as one of our strong missions as a company to provide that natural gas service in that rural service area to help with development, particularly economic

development as well.

Q Glenn, when Mr. Wuetcher was asking you some questions about the annual review process in connection with the proposed Alternative Regulation Plan, you described to some degree why you felt that that review would be better than conducting a rate case. Is it true that the anticipated review process would be less formal and more constructive than is normally experienced during rate cases?

A Yes, we believe it would.

Q Mr. Wuetcher also asked you about the inclusion of the Canada Mountain operations in this rate case as opposed to--as part of the gas cost recovery mechanism. When the rate design and cost of service studies were done in this case, what part did the Canada Mountain operation play in those two functions?

A Those were excluded. In other words, there were no cost of service done or those weren't considered in it, so if we were to try to roll those into base rates or out of the GCR that would have to be restudied and addressed and it was not.

Q When Ms. Blackford was questioning you about the three year review under the proposed Alternative Regulation Plan, there was some discussion about the scope of that review. Would you please refer to Item 8 of Delta's response to the June 4 Commission request in the Alt Reg case, which I believe is in the white notebook there next to you. Does the response to Item 8(a) set forth the scope of the anticipated review at the end of the three year period?

A Yes, it does.

MR. WATT:

That's all the questions I have Your Honor. Thank you.

CHAIRMAN HELTON:

Mr. Wuetcher, do you have much on recross?

MR. WUETCHER:

I don't believe I have any, I think I'm going to pass.

MS. BLACKFORD:

Just one question with reference to Item 8(a).

RECROSS EXAMINATION

BY MS. BLACKFORD:

Q Am I correct in saying that what it says is we do not envision an extensive review?

MR. WATT:

Let me object, Your Honor, it says what it says.

CHAIRMAN HELTON:

Ms. Blackford, rephrase your question or restate your question?

Q What detail can I determine from "we do not envision an extensive review," how can I figure out what that review might be?

A Well, are you referring to 8(a)?

Q Uh-huh, that very last phrase in the first paragraph?

A Okay, which phrase being?

Q We are not envisioning an extensive review.

MR. WATT:

Your Honor, let me object, that mischaracterizes what the document says.

A I don't see that in it, that's why I'm curious, I'm trying to understand your question.

Q Well, perhaps I'm misquoting it. Let's look at 8(a), or 6(a), I'm sorry, are we on 6(a) or 8(a)?

A I'm on 8.

Q I'm sorry.

A Because 8 was what he asked me the question about, not 6, earlier, that's why I am having a hard time.

Q I misread the number, I have another interrogatory in front of me, we will address that later.

CHAIRMAN HELTON:

That appears to be all the questions for this witness. We will take a--if we could be back by one o'clock, I have a lunch meeting, but we would like to get through as many witnesses today as possible, so if we could reconvene at one.

(OFF THE RECORD)

CHAIRMAN HELTON:

Mr. Watt, call your next witness.

MR. WATT:

John Hall.

(WITNESS DULY SWORN)

The witness, JOHN F. HALL, having first been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. WATT:

Q John, would you please state your name for the record?

A John F. Hall, H-a-l-l.

Q Where do you live?

A My business address is 3617 Lexington Road, Winchester, Kentucky 40391.

Q By whom are you employed?

A Delta Natural Gas Company.

Q What is your position?

A Vice President of Finance, Secretary and Treasurer.

Q Would you please briefly describe your duties at Delta?

A I am, basically, the CFO of the company and handle all the SEC work, regulatory work, and I have under me accounting and data processing.

Q Have you filed direct testimony on behalf of Delta in this proceeding?

A Yes, I have.

Q Are there any changes, corrections or

additions to that testimony?
A The only change I would mention is the one of short-term debt, it has gone up twice since we filed. As of today it is 5.89 instead of 5.41.
Q That's 5.89% interest rate on short-term debt?
A Yes.
Q Any other changes?
A No.
Q If I asked you the questions contained in your direct testimony today, would you give the same answers?
A Yes.
Q Have you filed any rebuttal testimony in this case?
A No.

MR. WATT:

We have no further questions Your Honor. We would move the admission of John's direct testimony as supplemented.

CHAIRMAN HELTON:

So ordered. Ms. Blackford?

MS. BLACKFORD:

Yes, I do have a few questions, if I may, to begin with I'll pass out what I want to mark as Cross Examination, mark for the record as Cross Examination Exhibit Number 1.

CROSS EXAMINATION

BY MS. BLACKFORD:

Q I handed that to you just so I wouldn't get up and trip in the middle of our questions. I'll be addressing it in just a few moments. If we can start, please, by having you turn to page five of your prefiled testimony being Case Number 176. Are you there?

A Yes, ma'am.

Q At line 12 you state that Schedule 9 shows the calculation of Delta's overall cost rate for capital, which is 9.41%, is that correct?

A Yes, ma'am.

Q And you have subsequently adjusted that to indicate that the true figure should be 9.24%, am I correct in that understanding?

A No, that is 9.24 if you--the cost rate is times the capital base.

Q I'm sorry, I did not hear you.

A I barely hear you too, so we are having trouble.

Q Do we not have a mike on or something.

A The 9.31 is the cost of capital at the--times the capital structure, the rates applicable to the capital structure. The 9.24, whatever the percent was, 9.24, that is the one if you get a return times the--that is applicable to the rate base. I'm not sure if I'm making myself clear.

Q Just a moment.

A I'm sorry, 9.31 is--I've got that backwards. 9.31 is the imputed capital structure divided by your rate base. The 9.24 is the imputed capital structure at the cost rates.

Q Would you save that spot and turn now with me to FR Number 6(h), that is in Volume One of three of the filing requirements.

MR. WATT:

What tab is that? Do you have that?

MS. BLACKFORD:

I want to say it is tab 25 if I'm not mistaken.

MR. WATT:

It is, thank you.

A That's correct.
Q Are you there?
A Yes.
Q Can you point to where on the Schedule 9 the calculation of Delta's overall cost rate for is capital is shown?
A It is not computed, but on Schedule 9--
Q Yes?
A --that is the rates that I have used, if you put in the rates of the 13.9, the cost of long-term debt and the cost of short-term debt, that's where you will come up with the rates.
Q Let's look now at the exhibit I just handed you.
A Okay.
Q On that exhibit--I'm sorry, I've turned you to the exhibit too early. All right. On Schedule 9 the ratio of columns, the structure entitled Imputed Capitalization corresponds with the right hand column of Section 9, that is common equity is 43.5%, long-term debt is 48.43%, and short-term debt is 8.07%, is that correct?

A That is correct.
Q And the capitalization is adjusted, if checked against the fourth column, are these figures also correct?
A Could you repeat that please?
Q Checking the cap--on the lower part of this exhibit if you were to compare the capitalization, as adjusted, against the fourth column from the right of Schedule 9, do these also accurately reflect what is there?
A Are you talking about before being imputed?
Q The ratios?
A Those ratios are correct, also.
Q All right. Looking back at page five of your prefiled testimony please check the cost rates shown on this exhibit against the ones that you show on lines 14 through 20 of your testimony. Are these correct on the cross-examination exhibit?
A The top one is, yes, and I assume the bottom one is, I don't know, I'd have to get my calculator out.
Q Please notice that the imputed capital

structure with a 9.24% is the same as receiving 14.08% on the actual capital structure. Is that a correct analysis?

MR. WATT:

Your Honor, may I have that question repeated, I did not hear it.

CHAIRMAN HELTON:

Pardon?

MR. WATT:

May I have that question repeated, I didn't hear it?

MS. BLACKFORD:

Is the microphone not on or am I not leaning forward. Bob, I'm not meaning to be obstreperous, I just can't figure out what is going on.

COMMISSIONER GILLIS:

I'm having a little hard time hearing, too.

CHAIRMAN HELTON:

I think also the A/C is on right now when it kicks off we probably won't have as much trouble. So, just be a little bit louder while it that is going on please. Is everybody comfortable? We will turn the A/C down. Okay.

Q Please notice that the imputed capital structure with a 9.24% return is the same as receiving a 14.08% return on the actual capital structure; isn't that correct?

A That is what it says, like I said, I haven't calculated this.

Q Isn't the use of an imputed capital structure the same as a back door approach to trying to get an authorized higher rate of return on equity?

A Yes, it is.

MS. BLACKFORD:

Thank you, that's all of my questions.

CHAIRMAN HELTON:

Mr. Wuetcher?

MR. WUETCHER:

Thank you, your Honor.

CROSS EXAMINATION

BY MR. WUETCHER:

Q Let me start out by saying good afternoon. Why is Delta's capitalization greater than Delta's proposed rate base?

A Why is Delta's capitalization greater than its proposed?

Q That's right, proposed rate base?

A Oh, proposed rate base. We had a few questions on that and I've put a lot of thought into that and there is a lot of reasons. A lot of companies that come in here they have different capital structures than us. Basically, they have equity and long-term debt and/or preferred stock only. We have short-term in ours, and the way we use our short-term is we use it like most people use their cash or short-term investments, we bring it up and down daily. And, so, it is called part of our long-term capital structure. But if you, at any one point in time, if we was to reduce our--some of our payables or something, we would increase our short-term debt. And so, any point in time it could be higher or lower than--so it is--as to why, that is one reason. I'm sure the cash working capital could be another reason.

Q Could you explain that a little bit more why the cash working capital would be another reason?

A Well, it is part of the rate base and it is imputed at 1/8% of the O&M. And if our O&M was higher, our rate base would be higher.

Q Okay.

A Or vice versa, if it was lower, it would be lower.

Q Okay. Does Delta's proposed capital structure include the capital that financed Delta's investment in cash surrender value of life insurance in the amount of $347,789?

A At one time it did, yes.

Q Does it now?

A Not to my understanding.

Q Can you tell me when it ceased to include that amount?

A No, I can't.

Q Could you provide that for us subsequently to--subsequent to this hearing?

A Sure.

MR. WATT:

What you want is the date that the cash

surrender value of life insurance no longer was part of the capital structure?

MR. WUETCHER:

Yes, sir.

MR. WATT:

Thank you.

Q Is the in-cash surrender value of the life insurance included or excluded from Delta's rate base?

A It is excluded from the rate base.

Q Is the capital supporting Delta's December 31, 1998, investment of deferred gas costs of $1,354,892 included in Delta's proposed capital structure?

A It could be in short-term debt.

Q Could you verify that for us?

A No, I cannot verify it, I don't know--

Q Well, I guess you are saying it could be, I guess the question is are you uncertain about that or--

A I'm uncertain, yes.

Q Could you check your answer for us then so that you are certain?

A Okay, sure.

Q Would you agree, subject to check, that in Case Number 97-066 Delta's capitalization exceeded its rate base by $504,003?

A Subject to check, yes.

Q And would you agree, subject to check, that in that proceeding the Commission applied the weighted cost of capital to net investment rate base to arrive at Delta's revenue requirement?

A They did and I disagreed with it.

Q Okay. Well, that was my next question. Why did Delta not use the same methodology that the Commission used in Case Number 97-066 to develop its proposed revenue requirement?

A Because I disagreed.

Q Okay.

A And the reason--

Q Yes, sir, go ahead.

A The reason was is if you take the numbers that Mr. Henkes has produced saying we needed a reduction of 132,000 at 10.75%, if you bring the numbers down and show the return on equity at that, it is not 10.75, it is 10.5. And so, if you, also, if you pay the debt, pay the interest on the debt that is applicable to the capital structure, then it reduces the return on equity to 10.1. So, we are short changing ourself, that's why I did it. And we were short changed in the last order, also.

Q Can you provide us the calculations to demonstrate that. I won't ask for it today.

A Sure.

Q I won't ask you to provide it today but if you could provide that so we could have something in the record that shows how Delta was short changed?

A I'd be glad to.

Q I think you had addressed some information requests in which you explained or were asked to provide some analysis as to why Delta had failed to earn its authorized return over the last ten years. Can you tell us what those factors are?

A This is in one of my data requests?

Q Yes, sir. Well, let me be a little bit more specific, I think you had identified in your data request the only factor that you did

identify was weather. Would that be correct?
A Could you tell me what data request so I can refresh my mind?
Q I was afraid you were going to ask that. Let me rephrase it, can you--in your opinion, why has Delta been unable to achieve its allowed rate of return over the last ten years?
A I'd say--other than the reasons Mr. Jennings stated, I would say weather has been one impact, incremental growth has led to one.
Q Can we just say weather has been the predominant factor?
A I don't know that it is predominant, the last four out of five years maybe.
Q Has there been an increase in capital cost over the ten year period and what impact, if there has been, has that played on Delta's inability to earn its allowed rate of return?
A The--it has gone up and down, I don't know that it is steadily going up, because I know in this case I think it is down from the previous year, two years ago.
Q Well, would an increase in capital cost have been one of the reasons for the inability to

meet the authorized rate of return?
A Yes, it hurts.
Q I'd like to go ahead and refer you to Delta's response to the Commission's Order of July 2, 1999, in Case Number 99-046.
A What's the number again please?
Q It is the July--I'm sorry, it's the first item to the information request.
MR. WATT:
Item 1 of the July 2 data request?
MR. WUETCHER:
Yes, sir.
Q Okay. Do you have that in front of you sir?
A Yes, I do.
Q Okay, in the second paragraph you state that in developing budgets for the fiscal year 2000 you evaluated why Delta has not been able to earn its authorized rate of return. I think you indicate that part of the reason was weather and, additionally, increased costs in investment. What are the cost increases that you were referring to from this analysis?
A This is the increase--I think it is increased cost and investments, the increased cost in

investments.

CHAIRMAN HELTON:

So, it should state "and" instead of "in," Mr. Hall?

A Well, it says increased cost "and" investments. Basically, there was not a lot of increase in costs, such as O&M.

Q Okay. Well, when you make the reference to increased cost, what particular cost are we speaking of, operation and maintenance costs?

A No, capital costs.

Q When you prepared your analysis, did you review the increased cost to determine whether the increases were controllable?

A Yes, always, none of them were controllable.

Q Can you explain to me how you identified that they are controllable?

A All costs are controllable to us.

Q And when you conducted--I'm sorry, you said when you conducted your review you determined that they were controllable or were not controllable?

A I'm saying all costs that we have are controllable.

Q Okay.
A We can cut out any part of the company.
Q After you conducted your analysis, did you consider any alternative to a rate increase, such as reductions to the year 2000 budgeted expenses?
A We always look at the--and compare our expenses from year to year and if you are speaking in particular of Y2K, there was none to--
Q No, I'm not talking about Y2K, I'm just saying you looked at the budget and when in making the decision--
A If there is any cost controllable that we should reduce, is that what you are saying?
Q Well, I'm saying when you were reviewing the cost, did you consider any alternatives to a rate increase, such as a reduction in any particular expense item?
A There was none that we felt that could be reduced. I'm saying that we can cut out services, anything, it is all controllable, in that sense that cost--we can reduce ten people but we are going to reduce services,

that's what I mean when I say it is controllable. I'm not saying that we have excess people or we have other things that we can control that way.

Q Well, just so I understand, then, what you are saying is that when you conducted your review you looked at the cost, they were all cut, at least in your alls opinion, to the bone.

A Absolutely.

Q And there was no other alternative available to a rate adjustment?

A That's true.

Q If you turn to the next page, I'm going to be referring to Response 2 to the Commission's Order of July 2. You are identified as the witness for that one.

MR. WATT:

You are on Item 2?

MR. WUETCHER:

I'm sorry, Item 2 of the response to the July 2 Order.

Q You state there that--did you not refer to your monthly and annual analysis of the budget versus actual financial information as analysis. You do, however, state that you do continuous analyses. What are some of the actions that might typically be taken by Delta when you have costs that are above budget?

A If it is already spent, there is nothing we can do. But if--oh, we live by our budget. By that I mean once we set the budget in place, hopefully, all costs from that point on will come in at budget. If anything that we know of is going to be outside of the budget that we, like I say, I'm going to pay more for insurance, et cetera, I have to get approval through Mr. Jennings and so, we know when those costs will be above the variance. So, also all costs are reviewed monthly by our analysis--it's not analysis, it's budget variances.

Q Well, let me see if I understand it. You have your annual budget?

A Yes.

Q And I assume that based on that you have at least an estimate of what you are--or budget as what you plan to spend each month. And based on your monthly reviews you can determine if a particular expense item is being incurred at too rapid a pace, that it would exhaust what you budgeted for that particular item before the end of the fiscal year, is that correct?

A Yes.

Q When you see that trend occurring through your monthly analysis, what is the next step that is taken?

A The next step is, if it is controllable, gas purchases, what can we do? We have got to purchase the gas, but labor, it is generally a one time thing, you know, it has been approved before hand. Magazine subscriptions, whatever, it has got to be explained. And we can't reduce it from that point on, but we can control it from that point on.

Q Okay. I'm still not following you and I apologize. When you see a troubled expense item, something that at least to you appears to be something you are spending too much on at too great a rate and it is going to be out of budget, you then at that point determine whether it is controllable or not, is that right?

A Yes. It is not as though we have got additional labor. That it's--one time we had overhead--or over time one month, and when it was explained that month, we can control it the next month by saying there is no more over time. But sometimes when there is an emergency or something, somebody has got to have some over time spent, so in that sense it is not controllable, but we can control it by saying you are not going to do it.

Q Tell me what is Delta's track record with regard to operating within the budget based on the analysis that it performed in response to the Attorney General's Data Request, Item Number 39 of the June 4 data request? And I believe that is, again, in Case Number 99-046, book three of three.

A This is O&M expense, right?

Q Yes, sir.

A The numbers speak for themselves.

Q Well, would you say you have been successful in operating within your budget?
A I would have to go back and look to see why the variances or what they are. Some are over and some are under, and if it was--I can't explain by just looking at the number. We get estimates for insurance, or such as that, and we put it in the budget, but if during the year the insurance is $200,000 more than what we had in the budget, does that mean that we don't buy the insurance.
Q Well, would you agree that the analysis that is set forth in response to Attorney General Data Request 39 reflects that only three out of ten years where Delta's actual O&M costs were within the budgeted amounts?
A That's according to what percent you are talking about.
Q No, I'm talking about actual results.
A The total O&M was within the budget amount?
Q Yes, sir.
A Oh, you are saying under budget, right? That's what the numbers say, yes.

MR. WUETCHER:

Thank you Mr. Hall. That's all we have.

CHAIRMAN HELTON:

Chairman Holmes, Mr. Gillis?

VICE CHAIRMAN HOLMES:

No questions.

COMMISSIONER GILLIS:

No questions.

CHAIRMAN HELTON:

Redirect?

MR. WATT:

I have just very brief, Your Honor.

REDIRECT EXAMINATION

BY MR. WATT:

Q John, is it Delta's recommendation in this case that a 13.9% return on equity is appropriate if you use Delta's actual capital structure?

A Yes, it is.

Q Would you please direct your attention to Attorney General Cross Exhibit Number 1. The table that is shown under the heading "Capitalization as Adjusted," is it your understanding that that is Delta's--close to Delta's actual capital structure, as of the date indicated?

A Yes.

Q So, that the 14.08% that results from the 9.24% weighted cost of capital is pretty close to the 13.9% that Delta recommends?

A Yes.

MR. WATT:

That's all I have Your Honor.

CHAIRMAN HELTON:

Ms. Blackford?

MS. BLACKFORD:

No further, thank you.

CHAIRMAN HELTON:

Ms. Blackford, I don't believe that we moved this into the record, you marked it Cross-Examination?

MS. BLACKFORD:

I'd like to move it into the record, please?

CHAIRMAN HELTON:

So ordered.

(EXHIBIT SO MARKED: Attorney General Cross Examination Exhibit No. 1)

CHAIRMAN HELTON:

Mr. Wuetcher?

MR. WUETCHER:

We have no further questions.

CHAIRMAN HELTON:

You're excused. Mr. Watt.

MR. WATT:

John Brown.

(WITNESS DULY SWORN)

The witness, JOHN B. BROWN, having first been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. WATT:

Q John, would you please state your name for the record please?
A John B. Brown.
Q Where do you live John?
A 1137 Lafayette Boulevard, Winchester, Kentucky.
Q By whom are you employed?
A Delta Natural Gas Company.
Q What is your position?
A Controller.
Q Would you very briefly describe your duties?
A I direct the accounting and financial

reporting and management information system activities at Delta.

Q Have you filed direct testimony on behalf of Delta in this proceeding?

A Yes, I have.

Q Are there any changes, corrections or additions to the testimony?

A No.

Q If I asked you the questions contained in your direct testimony today, would you give the same answers?

A Yes, I would.

Q Have you filed rebuttal testimony on behalf of Delta in this proceeding?

A Yes.

Q Are there any changes, corrections or additions to your rebuttal testimony?

A No.

Q If I asked you the questions contained in your rebuttal testimony today, would you give the same answers?

A Yes, I would.

MR. WATT:

We have no further questions Your Honor.

We would move the admission of John's direct and rebuttal testimony.

CHAIRMAN HELTON:

So ordered. Ms. Blackford?

MS. BLACKFORD:

Thank you.

CROSS EXAMINATION

BY MS. BLACKFORD:

Q I have a series of documents which I have compiled into what I will ask to have marked as Cross-Examination Exhibit Number 2. Cross-Examination Number 2 consists of three sheets, if you will turn with me to the first of them it simply lists the historic 401K expense numbers for the company, which were taken from the company's trial balances for the representative years. Would you accept, subject to check, that those numbers are correct?

A Yes, subject to check.

Q The expenses as shown on that sheet gradually increase from $114,000 in 1994 to $140,000 in 1997, but then jump to $180,000 in 1998; is that correct?

A Yes, subject to check.

Q And they rose approximately $40,000 in that last single year. The second page is the response to Attorney General's Data Request Number 53. There the company confirms that one of the reasons for this large increase is that the 1998 expense includes a reclassification of the pension expense due to an account distribution correction made for a trustee for the year of 1997; is that correct?
A Yes.
Q And the third page of this collective exhibit is the response to the Attorney General's Supplemental Data Request Number 22. That response confirms that without this reclassification for the 1997 account distribution correction, the 1998 401K expenses would have been $161,634; is that correct?
A Yes.

MS. BLACKFORD:

I move that this be moved--I move this into the record as Exhibit Number 2.

CHAIRMAN HELTON:

So ordered.

(EXHIBIT SO MARKED: Attorney General Cross Examination Exhibit No. 2)

Q Just to keep Mr. Henkes occupied and off the street, I have a collection which I will refer to for the purposes of identification as Cross-Examination Exhibit Number 3. This exhibit is, in fact, the response to Data Request Number 55 with its attachment, a schedule pertaining to Delta Natural Gas Company's uncollectibles, is that correct?

A Yes.

Q On the second page, line four, under the test year column that the--we see that the uncollectible expenses booked during the 1998 test year amount to $345,870 representing .99% of total revenues for the year; is that correct?

A Yes.

Q For 1997 the uncollectible expenses were $310,000 or .79% of revenues; is that also correct?

A Yes.

Q And for 1996 the uncollectible expenses were $150,000 or .45% of revenues; is that also correct?
A Yes.
Q Finally, for 1995 the uncollectible expenses were $100,800 or .45% of revenues; is that correct?
A No, that was `94.
Q I'm sorry. For 1995, am I reading--okay.
MR. WATT:
You're on the wrong column there.
Q Okay. I was on the wrong column, okay, 128,400 or .33%, correct?
CHAIRMAN HELTON:
No, ma'am, it is 128,400 and the percentage is .45.
Q Let me back up and try again. For 1995 the uncollectible expenses were 124,800 or .45% of revenues?
A No, the amount is 128,400.
Q And for 1993 and 1994 the uncollectible expenses were $100,800?
A Yes.
Q Or .33 to .36% of revenues; is that correct?

A Yes.
Q The uncollectible reserve ending balance at the end of the 1998 test year has grown to $155,773; is that correct?
A Subject to check, I don't have that in front of me.
Q I believe it is on that sheet in the final column.
A At the end of the test year you are saying?
Q Yes.
A Yes.

MS. BLACKFORD:

I'd move this into the record as Cross Exhibit Number 3.

CHAIRMAN HELTON:

So ordered.

(EXHIBIT SO MARKED: Attorney General Cross Examination Exhibit No. 3)

Q We'll refer to this for identification purposes as Attorney General Cross Exhibit Number 4. This exhibit consists of four documents, the first two of which are pages 325 of the company's 1998 and 1997 FERC Forms 2, do you recognize those as such?
A Yes.

Q And the third document is the response to Attorney General Data Request Number 49, and the fourth document is the response to the Public Service Commission Request Number 47, do you recognize those?

A Yes.

Q Look on the first document, it is page 325 of the 1998 FERC Form 2, there the company's 1998 test year expenses include $104,940 of regulatory Commission expenses; is that correct?

A Yes.

Q The second document shows that for 1997 these Account 928 regulatory commission expenses were about $63,000; is that also correct?

A Yes.

Q And in 1996 that sheet shows that these expenses were also about $63,000; is that correct?

A Yes.

Q In response to Attorney General's Data Request Number 49, which is the third sheet of this collection, the second page shows a breakout for the 1998 test year expense

amount and also shows that the major reason why the 1998 expense level of $104,940 is so much higher than the expense levels of $63,000 for the prior two years. And that reason is that the 1998 expenses include two expense bookings for the DOT Pipeline Safety Programs; is that correct?
A Yes.
Q Specifically, there is a $20,870 booking for the 1998 payment and then another booking of $23,960 for the same program which represents a prepayment for 1999; is that right?
A I am not sure about that, I believe there was another response.
Q All right. Let's--I'm sorry, I've jumped ahead of myself. On the final document, the final page of the final document, I believe that the answer was given that, in fact, that is a prepayment for 1999 and that would be the second for 1.928.00 regulatory commission expense, and the answer is, "Increase in PSC assessment and increase in revenues of Delta. DOT assessment of $23,960 applicable to 1999 was paid in the calendar year 1998."

A That is true. One point to note, though, that the actual PSC payment was in the $72,000 range in the test year. So, it was significant. It was significantly more than it had been in the past, so then you would have the $20,000 some dollars DOT on top of that.

Q There were two factors there?

A There were two factors, the overbooking was made relatively minor by the increases.

MS. BLACKFORD:

I would move this into the record as Exhibit Number 4.

CHAIRMAN HELTON:

So ordered.

(EXHIBIT SO MARKED: Attorney General Cross Examination Exhibit No. 4)

Q We are now passing out what I'd like to refer to as Cross Exhibit Number 5 for the record. Three items are included in this group. The second item, which is the third sheet of this group, has been prepared by Mr. Henkes to facilitate cross-examination. It shows the actual pension expenses booked by Delta from 1993 through 1998 in Account

926.02 as directly taken from the company's trial balances. Would you accept these numbers as accurate, subject to check?

A Yes, subject to check.

Q This sheet shows that the company's pension expenses have gradually decreased from $413,000 in 1993 to $293,000 in the 1998 test year; is that correct?

A Yes.

Q The third item in this group, the last two pages, is the response to PSC Data Request Number 44. In 44(b) the Commission requested the most recent actuarial report concerning the company's pension plan; am I right?

A Yes.

Q And in response to that the company submitted an actuarial report dated April 1, 1999, which was rather bulky. All I've included here is the cover sheet, do you recall having done that?

A Yes.

Q In fact, this report did not provide the most recent annual--actual annual pension expense level, so the information was again requested

in supplement AG 23, do you recall that?
A I don't recall the specific question.
Q Well, are you aware that it was not actually included in that report?
A Are you referring to the actuarial report in the--
Q Report, yes.
A I recognize this exhibit, if that is what you are asking.
Q All right. The Supplemental AG 23 is actually the first page of this report, first two pages of this report, or of this exhibit, I'm sorry. In response to this request you stated that the most recent annual pension expense as per the most recent official actuarial report is $181,167; is that correct?
A That was as of the most recent financial statements, June 30, `99, for financial statement purposes.
Q On page seven of your rebuttal testimony you explained this actuarial determined pension expense amount does not include actuary expenses, trustee expenses, and pension

benefit guarantee corporation expenses; am I right?
A That's true.
Q And the total of those expenses would be $40,354 in 1998; is that accurate?
A Yes, during the test year.
Q If we are to add that $40,354 to the $181,167, the math works out to a total pension amount of $221,521; is that correct?
A That's true.
Q And this would be comparable to the actual 1998 pension expenses of $292,818 as was requested in that data request; is that right?
A Well, other than the fact that we are mixing two plan years. The test year covered two different plan years, one where the actual--actuarial evaluation was higher and one that was lower. So, by computing it that way you are taking the lower of the two.
Q Okay.
A So, that would be the difference.
Q And that is the most recent one of the two?
A That's right, through 1999.

Q On the first page of the supplemental of the response to AG Supplemental 23, it shows that the company's pension plan has been in an over-funded status since 1995; am I right?
A Yes.
Q And the over-funding was recently--has recently increased from about $500,000 in 1997 to about 1.9 million in 1998?
A That's true.
Q When the pension plan is over-funded, the earnings from the over-funding go towards reducing the future pension expense accruals; is that generally true?
A Well, that's one factor, but there are several other factors that come into play when determining pension expense for actuarial. I'm not an actuary so I don't pretend to understand those, but I do know that in light of this we have since received the year 2000 actuarial evaluation and it is significantly higher than the `99 was, which counters the argument that you are making. Other things that go into that are the earnings of the assets and it just happens to

be that on the last--over the last period the assets earned lower than expected. So, that would cut the other way. And that is a fact what has happened and why the year 2000 expenses are so much higher.

Q In your rebuttal testimony on page eight you state that Delta received the net pension expense at April 1, 2000, from the actuary and that the annual amount is $267,238; is that what you were saying?

A That's right.

Q Does this amount come from an official actuary report such as the one that was provided in response to PSC 44 or is this just a preliminary estimate from an actuary that you have received by phone call, letter, whatever?

A No, it is the precise exhibit that you have given me, just a year later.

Q So, you are saying that it is actually in the report, but a year later?

A It is, as you pointed out earlier, the actuarial valuation is not in the official reports.

Q Right.
A So--but it is as official as this document that you have for `99. We--it is prepared by Hand and Associates under the same.
Q Could we have a copy of that?
A Yes.
Q Okay. Thank you, that's all my questions on that one. I move that Cross Examination Number 5 be placed in the record.

CHAIRMAN HELTON:

So ordered.

(EXHIBIT SO MARKED: Attorney General Cross Examination Exhibit No. 5)

Q Mr. Brown, the actual 1998 test year medical cost in Account 926.04 amounts to $729,269; is that right?
A Yes, subject to check.
Q The cost of $729,269 represents a gross cost amount. It has not been reduced by amounts allocated to construction and subsidiaries; is that right?
A Yes.
Q The medical coverage amounts allocated to construction and subsidiaries associated with the

gross test year cost amount of $729,269 are included in the expense credit Account 922.00 entitled Expenses Transferred; is that right?

A Yes.

Q In this case Mr. Henkes has assumed that the appropriate O&M expense factor, i.e., the percentage remaining after the allocation to construction and subsidiaries is 73.98% and the company has agreed with that assumption; am I right?

A Yes.

Q In fact, you have used this same factor for the pension expense adjustment calculated on page six of your rebuttal testimony; is that so?

A Yes.

Q Prior to your rebuttal testimony, the company proposed to increase its 1998 test year medical coverage expenses by $77,561; is that right?

A Yes, subject to check.

Q And the AG took no exception to this proposed adjustment. The AG has now discovered that the $77,561 cost adjustment proposed by the company and left unadjusted by us represents a gross cost adjustment that was not reduced to reflect the amounts allocated to construction and subsidiaries; is that an accurate statement? Is it accurate that there was no reduction, that that is a gross cost?

A Yes.

Q So, the appropriate adjustment should have been 77,561 times the O&M ratio of 73.98% or $57,380, if the math--assuming the math is correct?

A Yes.

Q And would you accept this as a proper functioning of math, subject to check?

A Subject to check.

Q I'd like to move to your rebuttal testimony at page five, line eight. Are you there?

A Yes.

Q There you have calculated that the revised total pro forma medical expenses should be $900,970; is that right?

A Well, I think that the--that amount is not necessarily our pro forma amount. It is--it is more an illustration of a few of the accounts that, if similarly treated as a whole, as some of the accounts that the Attorney General has pulled out, that it would be such. We are not really proposing that this is the way that we would have calculated it because we would have calculated it that way to begin with.

Q All right. Well, if we take that assumption a little further, this is a gross number; is that right? It's unadjusted?

A Yes.

Q And it would result in an expense adjustment of $171,701?

A Yes.

Q After you apply the expense factor of 73.98% to the total proposed adjustment that adjustment would be $171,701 times 73.98% or $127,024, if that made any sense. 127,024, I wasn't going to spit those out in words to save myself.

A Subject to check.

Q Subject to check on the math. And since you used 77,561 as the original cost adjustment,

the difference between the two amounts would be $49,463; is that correct?
A Subject to check?
Q As opposed to the $94,100 that was claimed in the testimony on line 11?
A Again, subject to check.
Q In your rebuttal testimony you state that in calculating the medical expense adjustment you used the same methodology as was used by Mr. Henkes in his Schedule RJH-14 for uncollectible expenses; am I accurate in that statement?
A Yes.
Q First, can you tell me in what way your methodology is similar to that of Mr. Henkes' in RJH-14?
A Well, just basically taking an average of history and projecting it, calculating it based on another factor that is relevant. The other exhibit that you referred to was about uncollectible expense, so there is a relationship between uncollectible expense and revenue, I believe, was the other factor. So, this was just saying that there is a

relationship between medical plan expense and payroll. And then looking at that relationship over a few years and applying an average percentage to an amount which is in the test year.

Q All right. Theoretically what you are doing is similar, but methodologically is it similar? Did you look only at historic costs?

A Just at historic costs.

Q But you included 1999 cost beyond the test year; is that right?

A Yes. Let me back up. Did use the most recent information and the reason for that was the experience of rising health care costs. We felt that the most recent information was the most relevant.

Q So, this is post test year information, as Mr. Seely would deem it?

A Some of it could be characterized as that. I believe, though, that the point is not necessarily the--like I said earlier, the amount derived here, the overall point is the fact that, you know, we are taking accounts that we are alleging are higher in the test year and we are just trying to illustrate a few of the accounts that are possibly lower in the test year, to make that point. And, again, I back up, this calculation methodology is not the company's original. We would have--we stand by what we originally have in our case. This is illustration purposes to--for the testimony of the Attorney General.

MS. BLACKFORD:

Okay, just a second. Thank you. There is no need to move this into the record, we will just pull it out.

Q Let me discuss the training schools with you for a second. On pages five and six of your rebuttal testimony you discuss the fees training school expense in account 1.880.01 and state that the 1998 expense level for this expense type is abnormally low; right?

A Yes.

Q The 1998 expense for this item was $14,173 and the 1997 expense for this item was $51,436; is that accurate?

A Yes.

Q What is the expense level for this item in 1999 through October for the first ten months of this year; do you know?

A I don't know that.

Q Can you provide that?

A That can be provided, yes.

Q In your testimony you claim that when you average the 1997 expense level of $51,436 and the annualized 1999 expense level of $40,304 you arrived at a proper normalized expense level of $45,870; is that accurate?

A Yes.

Q In this averaging methodology have you totally ignored the actual expenses of 1998?

A Yes.

MR. WATT:

Your Honor.

Q Now, let me address small tools for a moment.

MR. WATT:

Your Honor, before we go to small tools, I was looking for something over there when the last request for the provision of an item occurred, could I have that repeated please?

MS. BLACKFORD:

Surely. That was for the expense level for fees training schools in 1999 through October, or to date, since we are nigh onto November.

MR. WATT:

Thank you, I apologize.

Q Taking up small tools. On page six of your rebuttal testimony you discuss small tools expense in Account 1.900.03 and you state that the 1998 expense level for this expense type again is abnormally low. The 1998 expense for this item was $53,056 and the 1997 expense for this item was $82,435; is that right?

A Yes.

Q What is the expense level for this item in 1999, again, through date; do you know?

A I do not.

Q Would you be willing to provide that?

A Yes.

Q You say there that you have averaged the 1997 expense level of $82,435 and the annualized

1999 expense level of $64,995 and arrived at a proper normalized expense level of $73,715; am I right?
A Yes.
Q In this averaging methodology have you totally ignored the actual expenses in 1998?
A Yes.
MS. BLACKFORD:
Thank you, that's all my questions.
CHAIRMAN HELTON:
Mr. Wuetcher?
MR. WUETCHER:
Thank you.

CROSS EXAMINATION

BY MR. WUETCHER:
Q Good afternoon Mr. Brown.
A Hi.
Q Let me start out, I think the AG had previously requested that you provide a copy of the April 1, 2000, net pension expense or a copy of the actuarial report for--
A Yes.
Q Could you also provide to the Commission the

1999 and, if you haven't, the estimated or the year 2000 expenses for--that are to be paid to Hand and Associates, American Industry Trust Company and the Pension Benefit Guarantee Corporation?

A Yes.

Q Delta's annual pension expense decreased--

MR. WATT:

Just as moment, could I have those again so I can get the notes taken? Hand and Associates--

MR. WUETCHER:

Hand and Associates, American Industry Trust Company and the Pension Benefit Guarantee Corporation.

MR. WATT:

Thank you.

Q Just to clarify for the record, would there be any other parties that would also be paid expenses other than these parties related to the pension expense?

A No.

Q Delta's annual pension expense decreased between June 30, 1998, and June 30, 1999, by 33%, and increased by 48% between June 30, 1999, and June 30, 2000, by 48%. Why would Delta's annual pension expense fluctuate so drastically?

A Well, our annual pension expenses, the fluctuation is driven mostly by the actuarial valuation which, like I said earlier, the foundation which the actuary uses to establish that every year, there are several factors that come into that, the degree of funding, the return on the assets, the number of retirees you have and the aging. There is several--several items that factor into that and we--and for that very reason is why we have to hire an actuary to come up with that amount. So, basically, we rely on Hand and Associates in calculating the expense that we should book each year and we book the amount that they give us.

Q Then would it be correct to say you don't know but if the answer is in the actuarial--if your actuary has provided it to you, it would be in the report that you are going to be providing the Commission?

A Actually, the one page report does not have any narrative on it.

COMMISSIONER GILLIS:

That much of a change from one year to the next there should be a few isolated things that cause that much change. Do you know what those were?

A I do know that our earnings on our plan have fluctuated greatly over the last two or three years. The year ended April of `98 had excellent performance. It out performed expectations. The year ended `99 was virtually break even, which was seriously under expectations. You know, Delta has not had a significant change in its employees, its compensation levels, retirees, so the big changes--we have not changed the plans significantly, you know, anything that you would look at. So, it is driven by those market conditions.

Q Do you agree that overtime and part-time labor should be reflected in Delta's pro forma operations?

A I think that depends on what the number is being used for, you know, there are some

places that it is appropriate to consider those numbers and some places they may not be.
Q Okay. Well, let me clarify it a little more. When we are speaking in terms of payroll, would you agree that overtime and part-time labor should be reflected in Delta's pro forma operations?
A If you are trying to get a full picture of what your direct payroll costs are, you would want to know those. But, you know, there are, I'm sure, instances where you would want to do calculations with those excluded since it is a different character.
Q Does Delta--Delta's proposed payroll adjustment of $116,199 represent a gross adjustment that includes labor costs either capitalized or charged to clearing accounts?
A Let me pull that adjustment.
Q Okay.
A So, you are referring to the 116,200 adjustment to payroll and you are asking whether that includes--
Q Whether that represents a gross adjustment

that includes labor costs either capitalized or charged to clearing accounts?
A Yes.
Q Would you agree, subject to check, that Delta charged $4,531,719 to its operation and maintenance expenses during the test period?
A Yes, subject to check.
Q Okay. Have you reviewed the Attorney General's proposed reduction to Delta's payroll adjustment to reflect only the portion of payroll increase that will be charged to the operation and maintenance expense?
A Yes, I have.
Q Do you agree with it?
A Yes, in theory.
Q If you will refer to Delta's response to Item 23 of the Commission's September 14, 1999, Order. Based upon this response would you agree that the pro forma payroll that would be charged to operations--
A Excuse me, could you let me find that?
Q I'm sorry, go ahead, it is Item 23 of the--of Delta's response to the Commission's Order of

September 14, 1999.

MR. WATT:

Do you have it John?

A Yes, I have that.

Q Okay. Based upon this response, would you agree that the pro forma payroll that would be charged to operations and maintenance expense would be 4,612,184?

A Can you direct me to where that number appears?

Q Okay. Which, the four million number?

A Yes.

Q The number I just--okay, well, I don't believe it appears on there. I can--why don't I take you through it and see if you agree with it?

A Okay.

Q If you take payroll of 6,213,582, which, if you will look at page five of the response,--

A Right, I see it.

Q Okay. And then subtract from that $1,595,398 for capitalized labor, which--okay, do you agree with that?

A Uh-huh.

Q And then also subtract $6,000 related for--to subsidiaries, that would produce the $4,612,184?
A Yes, subject to check.
Q So, it is yes, subject to check, for the entire answer?
A Right.
Q Okay. Would you agree, subject to check, that if the $4,612,184 pro forma payroll is used, then the payroll adjustment would be $80,465 rather than Delta's proposed adjustment of $116,199?
A Yes, subject to check.
Q If you will refer to Delta's response to Item 25 of the Commission's September 14, 1999, Order, do you have that?
A Yes.
Q Okay. Is Delta proposing to increase Account 1.920.01 styled Administrative Payroll by $24,000 to reflect compensation paid to Glenn Jennings in the form of a loan payment forgiveness?
A Yes.
Q Does Delta's pro forma salaries and wages

calculated in response to Item 23 of the Commission's September 14, 1999, Order include the $24,000 loan payment forgiveness to Mr. Jennings?

A I don't believe so, but I'd have to find the schedule to verify that.

Q Do you want to take a moment and take a look at that schedule?

A The Attorney General's request, their first request, August 11, `99, question 37, asks if the PSC Report also includes 1998 test year above the line expenses including the $24,000 loan forgiveness that were disallowed for rate making purposes, please confirm this. And in this response we confirmed that the $24,000 is included in the test year.

Q So, would the answer to my question be yes?

A My concern here is that these numbers, I don't have, you know, the 435.

Q Well, why don't we do this, then, do you believe right now that it possibly could be but you want to go ahead and check it to insure, to verify that?

A The way I understood it was that that was

erroneously left out of the test year initially. And then the request, the answer to the question that you first directed me to was our way of suggesting that it should not have been left out. But there have been so many requests about payroll, I'm not clear on which schedule it is and which schedule it is out. So, I'd really need to--but I'm sure there is information in the data request that gives that answer.
Q If you could go ahead and subsequently verify that for us and the--what we are referring to, again, is the schedule that was submitted in response to the Commission's Order, Item 23 of the Commission's Order of September 14, 1999?
A The--I think you will find that Mr. Hall and Mr. Jennings sponsored a lot of the data requests that had to do with the $24,000, so you might be able to get a direct answer today from them.
Q Okay. Well, I think you were responsible for that particular schedule, you are listed for the sponsoring witness for that item. Moving on to, very briefly, the 401K expense. Why

is it appropriate to include a prior period trustee fee in Delta's test period 401K expense?

A We are not saying that it is proper, we are saying that that specific item being in that expense account does not render the O&M test year non-representative, because we feel there are other accounts that have items which go the other way in equal or greater amounts.

Q Since the 401K expense is a cost that is directly related to labor, should a portion of this expense be allocated to Delta's construction and subsidiaries?

A Well, that is an employee benefit which does get allocated through our overhead process.

Q Okay. I think here we are trying to address the proposed adjustment.

A Well, then, it would fall under the same category as medical and such, yes.

Q Does allowing Delta to recover the cost associated with two rate cases represent an abnormal annual expense level?

A It is not abnormal if that is the situation.

If the costs have been incurred, we have had rate cases close together and those rate cases accumulate costs which need to be amortized. To that extent it is not abnormal.

Q Are you familiar with the normalization method that the Attorney General has proposed for Delta's rate case expense?

A Yes.

Q Would eliminating the amortization expense of Delta's prior rate case, as the Attorney General proposes, be disallowing the recovery of a legitimate operating expense?

A Yes.

Q What changes did Delta make in 1999 to more aggressively enforce its collection policies?

A We, basically, developed better reporting, internal reporting, on activities related to collections and raised awareness throughout the company.

Q Can you be a little bit more specific on that? When you say you developed more reporting policies, does that mean somebody internally who wasn't aware of what was going

on before now became aware of it?
A Well, I think it raised awareness.
Q Would you explain why Delta, then, changed its bad debt collection policies in 1999?
A Well, the--like you said, we didn't change our policies, we have just developed, we feel, at least we are hoping, some reports and some procedures to help us enforce our policies, our existing policies.
Q Would it be correct, then, to say that the changes were to heighten awareness of the existing situation?
A Yes.

CHAIRMAN HELTON:

Mr. Brown, would you explain how that is going to help collections? I mean, you didn't change your policy, so you don't call a customer earlier than you did before or send them a notice earlier than you did before, so how is raising awareness within the company going to change the level of your uncollectibles?

A Well, you know, the aggressiveness to which you collect, your efforts of going to the house, making that call to get the collection, the--those things are left--are rather--are more subjective than objective, I guess, and, you know, we began keeping some statistics on the amount of, basically, service orders that get generated and then are followed up with the collection folks going to the house and collecting. And just, basically, raising awareness of the importance of being very strict with those policies we hope will help with the collection efforts.

CHAIRMAN HELTON:

So, more adherence to the policies you already had in place, is that what you are saying?

A Yes.

Q Have you reviewed the Attorney General's proposed property tax adjustment?

A Yes.

Q Do you agree with that proposed adjustment?

A Let me tell you what I remember and make sure. Is this concerning Canada Mountain, the amount of property tax?

Q Yes, it is.

A Yes.

Q Does Delta pay property taxes based on net utility plant and construction work in progress and cushion gas?
A Yes.
Q Do you agree with the Attorney General in that Delta's proposed income tax adjustment should include the annual investment tax credit amortization of $71,000?
A Yes.
Q And, in your opinion, should the amortization of the excess deferred income taxes as of December 31, 1998, that resulted from the change in the federal income tax rate from 46% to 35% be included in Delta's proposed adjustment?
A Yes.

MR. WUETCHER:

That's all I have. Thank you very much.

CHAIRMAN HELTON:

Redirect? Should I ask if there is going to be much redirect or recross, would you like to take a break or maybe try to finish this witness?

MR. WATT:

Mine is really very brief.

REDIRECT EXAMINATION

BY MR. WATT:

Q John, you were asked some questions a moment ago about the pension expense where you were going to provide 99 and 2000 expenses from Hand and Associates and those others, do you remember that?

A Yes.

Q Is life insurance also a part of pension expense?

A Yes.

Q So, that was omitted when you were discussing kinds of expense?

A Well, yes and no. Those pay--life insurance payments are typically made to American Industries which is one of the institutions which was mentioned.

Q Okay. So it would be included in the information you will be providing?

A Yes.

Q Has the funded status of the employee benefit plans decreased from fiscal year end `98 to fiscal year end `99?

A I don't know the answer to that.

MR. WATT:

That's all I have Your Honor.

CHAIRMAN HELTON:

Recross?

MS. BLACKFORD:

Thank you, nothing.

MR. WUETCHER:

We have just a couple of items.

RECROSS EXAMINATION

BY MR. WUETCHER:

Q When you provide the expense levels related to the companies we mentioned at the beginning of the cross-examination, would you break that down as far as what relates to pension expense and life insurance expense?

A Okay.

Q And, also, can Delta provide an update on its rate case expense itemizing the types of service received for those expenses and in what case the expense was incurred? By that I'm referring to, if an expense was incurred in the preparation of 99-046, that that expense be indicated as being prepared in that case as opposed to the current rate case? And, also, can Delta provide the invoices for its legal and consulting services that it has used for this rate case?

A Sure.

MR. WUETCHER:

That's all we have. Thank you.

CHAIRMAN HELTON:

Thank you, you may be excused. Let's take a break, 15 minute break.

(OFF THE RECORD)

CHAIRMAN HELTON:

Mr. Watt, your next witness.

MR. WATT:

Robert Hazelrigg.

(WITNESS DULY SWORN)

The witness, ROBERT C. HAZELRIGG, having first been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. WATT:

Q Bob, would you please state your name for the record?

A Robert C. Hazelrigg.

Q Where do you live?

A 71 Mockingbird Valley Road, Winchester, Kentucky.
Q By whom are you employed?
A Delta Natural Gas Company.
Q What is your position?
A Vice President of Public and Consumer Affairs.
Q Would you please briefly describe your duties?
A I'm primarily responsible for governmental, public and media relations, as well as economic development and our large volume customer accounts.
Q Bob, have you caused Delta to publish legal notice of this hearing and this proceeding?
A Yes, I have.
MR. WATT:
Your Honor, we would like to mark this packet of affidavits of publication as Delta Hearing Exhibit Number 1 collectively.
CHAIRMAN HELTON:
So ordered.
Q Bob, I'm handing you Delta Exhibit Number 1

and I'll ask you if those are the affidavits of publication which the newspapers have sent you?

A Yes, they are.

MR. WATT:

I move their admission as Delta Exhibit 1.

CHAIRMAN HELTON:

So ordered.

(EXHIBIT SO MARKED: Delta Exhibit No. 1)

Q Have you filed direct testimony on behalf of Delta Gas in this proceeding?

A Yes.

Q Are there any changes, corrections or additions to that testimony?

A I do have two corrections to make. As stated in my response to question four of the Public Service Commission's August 11 data request, the reference to the 25 cent difference between GS and interruptible service on page four, line 13 of my direct testimony, should state prior to rate case "90-342" rather than "97-066." Additionally, on page five, line 14 in my direction testimony, it should read

"interstate or intrastate" rather than
"interstate in intrastate" pipelines.
Q Subject to those corrections, if I asked you the questions contained in your direct testimony today, would you give the same answers?
A Yes, I would.
Q Have you filed rebuttal testimony on behalf of Delta in this proceeding?
A No.
MR. WATT:
We have no further questions Your Honor. We would move the admission of Mr. Hazelrigg's testimony as part of the record.
CHAIRMAN HELTON:
So ordered. Ms. Blackford?

CROSS EXAMINATION

BY MS. BLACKFORD:
Q Mr. Hazelrigg, I only want to ask you about your advertisements. Did you issue new advertising in conjunction with the two new tariffs that were filed or the tariff sheets that were filed on

October 25 in connection with the testimony in
this proceeding?
A No.
MS. BLACKFORD:
Thank you.
CHAIRMAN HELTON:
Mr. Wuetcher?
MR. WUETCHER:
No questions.
MR. WATT:
I have no questions, Your Honor.
CHAIRMAN HELTON:
Okay, I believe you are dismissed. Mr. Watt.
MR. WATT:
Martin Blake.
(WITNESS DULY SWORN)

The witness, MARTIN J. BLAKE, having first been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. WATT:
Q Dr. Blake, would you please state your name for
the record?
A Martin J. Blake.

Q Where do you live?
A 6711 Fallen Leaf, Louisville, Kentucky 40241.
Q By whom are you employed?
A The Prime Group, LLC.
Q What is the purpose of your testimony in this proceeding?
A The purpose of my testimony in this proceeding is to address the appropriate return on equity for use in this proceeding.
Q Are there any changes, corrections or--excuse me. Have you filed direct testimony on behalf of Delta in this proceeding?
A Yes, I have.
Q Are there any changes, corrections or additions to that testimony?
A Yes, there are.
Q Let me show you a document that we have marked Delta Hearing Exhibit Number 2 and would you please explain what that exhibit is in the context of any changes, corrections or additions to your testimony?
A Yes, I will. I will address this one first. This is an exhibit that I did, as you can tell, by hand while listening to the other

witnesses in response to Attorney General Cross Exhibit Number 1. The other changes that I have are in my testimony in Exhibit MJ-4, page two. The calculation using the Edward Jones analyst growth rate, the ROEs should not be ".03," they should be ".02." The calculation is correct, it is just a typo on the .03. It says ".03" and it should be ".02." The other is a change on MJB-5, Exhibit MJB-5, and in the first column of interest coverage about 2/3 of the way down for South Jersey Industries, Inc., that should be "2.26" instead of "2.36." And those are the only changes that I have to my testimony.

Q Dr. Blake, if I asked you the questions contained in your direct testimony today, subject to the changes that you have just described, would you give the same answers?

A Yes, I would.

Q Have you filed rebuttal testimony on behalf of Delta in this proceeding?

A Yes, I did.

Q Are there any changes, corrections or

additions to the rebuttal testimony?
A No, there are none.
Q If I asked you the questions contained in your rebuttal testimony today, would you give the same answers?
A Yes, I would.
Q Dr. Blake, I'd like to direct your attention to Attorney General Cross Exhibit Number 1, do you have a copy of that before you?
A Yes, I do.
Q And Delta Exhibit Number 2?
A I also have that, yes, I have them both.
Q What I'm talking about is the handwritten one?
A Right.
Q Would you please explain to the Commission what you have done on Delta Exhibit Number 2 as it relates to Attorney General Exhibit 1?
A You bet. As I understand it, the Attorney General Cross Examination Exhibit Number 1 illustrates a pretty well-known principle that capital structure changes have little impact on a utility's revenue requirements or its customer bills. However, the capital

structure does affect the cost of both debt and equity but changes in those variables are offset by changes in the weights of each capital structure component. And if you take a look at that, the Attorney General showed that one way where the Attorney General made the point that the use of an 11.9 in an imputed cap structure was similar to the use of a 14.08 with no imputed cap structure. What Delta Exhibit Number 2 does is show it the other way around, the use of the capital structure or the cost of equity that I recommend in this proceeding using the existing capital structure for Delta would be the same as a 10.4% rate of return for a company with a 43 1/2% equity. And that 10.4%, just personal opinion, I don't think the Commission would grant anything quite that low. And so, I think it is important to know that that principle cuts both ways. That's all I have on that.

MR. WATT:

I have no further questions, Your Honor. We would move the admission of Dr.

Blake's direct and rebuttal testimony
and the admission of Delta Exhibit 2.

CHAIRMAN HELTON:

So ordered.

(EXHIBIT SO MARKED: Delta Exhibit No. 2)

CHAIRMAN HELTON:

Ms. Blackford?

MS. BLACKFORD:

Yes.

CROSS EXAMINATION

BY MS. BLACKFORD:

Q Just to be sure your exhibit is merely showing that the sword can cut both ways, it is not what you are recommending in any way?

A I am not recommending that, just showing how it does cut both ways.

Q Dr. Blake, please refer to page 17 of your prefiled testimony.

A Okay.

MR. WATT:

Case 99-176?

MS. BLACKFORD:

Yes.

COMMISSIONER GILLIS:

What page is it on?

MS. BLACKFORD:

Page 17 beginning at line one.

A Yes.

Q The first part of the sentence of the quote which begins at line one states "the data did no permit analysis outside of the 42.5 to 54% debt range so we cannot state exactly what would happen," is that accurate?

A That's correct.

Q Dr. Blake, please turn to your Exhibit MJB-1.

A Yes.

Q Am I correct in interpreting the column labeled "Original Equity Percent" as excluding short-term debt and the column labeled New Equity Percent includes short-term debt?

A Yes.

Q Do you know if the study you site on page 17 included or excluded short-term debt?

A I don't know.

Q If a company had more debt than 54%, it would have had less equity than 46%; correct?

A Yes.
Q And, as you said, you do not know how many companies shown have more debt than 54% or equity less than 46% when short-term debt is excluded?
A The data in MJB Exhibit 1 was not the data used to do the article by Brigham, it is different data sets. Are you trying to compare--
Q I'm just trying to find out--I'm merely trying to find out whether the statement that was reflected in that first line is accurately reflected in your exhibit. It appears that there are a series of companies shown there, some seven of them, which, in fact, do have more debt than 54% or equity less than 46% when short-term debt is excluded.
A Like I say, the data set was not the data set used to conduct the study by Brigham.
Q Uh-huh.
A That is a quote from an article, published article, by Brigham from 1987.
Q In your MJB-1--

A Yes.

Q --is it correct that there are some 20 companies that have more than 54% or equity less than 46% when the short-term debt is included?

A I didn't count them but, subject to check, yes.

Q Please turn to page 20 of your testimony.

A Yes.

Q On line 16 you state that the cost of equity is based on the equation which defines the appropriate return on equity as the discount rate that equates the stock price of the stream of expected future dividends; is that right?

A Yes.

Q In financial jargon when something is an expected value, isn't it a future value and isn't the term expected future a redundancy?

A Sure.

Q The Equation 1 shown on line 19 shows that P, the price of stock, is equal to discounted dividends. Is $D_1$, $D_2$ and $D_3$ in the equation the expected future dividend stream you are

referring to?
A Yes, it would be one year out, two year out, three year out and so forth.
Q Please turn to page 21.
A Yes.
Q Equation 2 on line six shows $D_1$ is the same-- is that the same $D_1$ that was shown in Equation 1 on the preceding page.
A Yes. What that shows is that the dividend in the year sub 2, or two years out, is equal a dividend one year out times the growth rate.
Q At the top of page 21 you shows that $D_2$ equals, as you just said, $D_1$ times G; is this correct?
A Correct.
Q Please turn to Exhibit MJB-4, page one.
A Yes.
Q The bottom three equations shown on MJB-4 show that you used $1.14 as the dividend; is that right?
A Yes.
Q Is the $1.14 the same $D_1$ required by the DCF model or is it analogous to a $D_0$?
A It is my understanding that that would be the $D_1$.

Q And not the $D_0$. To convert the $D_0$ to a $D_1$ shouldn't we multiply it by G as you have shown at the top of page 21?

A Yes.

Q So, in Exhibit MJB-4, page one, the $1.14 which represents $D_0$ should be multiplied by G or 5.7% so that we get .065; is that right? Would $D_1$ actually be 6 1/2 cents?

A Would $D_1$ be what?

Q I'm sorry?

A Would $D_1$ be--

Q Six and one-half cents.

A No.

Q It's actually 1 plus G so we should get $1.02 or $1.20.5; is that right?

A No, I don't think. I don't have a calculator, I don't know what you are doing.

Q Well, are we agreed that $D_0$ should be $1.14?

A Since Delta hasn't changed their dividend in the last several years, I don't know that it would make much of a difference, but $1.14.

Q And if you were to multiple that by 1 plus G, G being .057.

A All right.

Q You would get 1.205; is that right?
A Oh, I see what you are doing, yes.
Q Dr. Blake, on MJB-4, page three, you show your use of a two stage DCF model; is that correct?
A Yes.
Q Turn with me please to page 24 of your testimony.
A Yes.
Q Lines one through four on that page indicate that in the two stage model dividends are assumed to grow at the analyst forecast for the first five years, and then at the industry growth rate after that; is that a proper summation?
A Yes.
Q Turn back please to MJD-4, page 3. In your use of the two stage model, did you use \$1.14 as $D_1$ or did you increase the \$1.14 by one plus G to get $D_1$?
A To be honest, I'm not sure.
Q Irrespective of what you use for $D_1$, did you grow the dividend at the estimated rate for Delta for five years and then switch to the

5.7 growth rate in year six when you implemented the model?

A No. I explained that in one of the responses to a data request that I grew it at the analyst rate for the first five years and then after, in the 20th year, started growing it at the industry average and used a linear trend to give a smooth transition between the two instead of just going from 2% to 5% which appeared a bit unrealistic. This smooths the trend out over a longer period of time. It would also lead to a more conservative result, a lower result than jumping immediately to the 5%.

Q Is this the method that you describe on page 24 of your testimony?

A No, it is not.

Q Have you utilized the method described in your testimony to determine what the results would be?

A That--the results do reflect what I just described. It is a transition to a growth rate after 20 years. Staff, in response to a data request, staff asked for the work papers to generate that and that's when I found that there was a difference in the description in the--it's response to Item Number 54 in the August 23 PSC Data Request.

Q In 176?

A Yes.

Q Case Number 176?

A Yes. And it describes the methodology that I just described and what is contained in MJB-4 on page three corresponds to the methodology described in the response to Number 54.

Q All right. And that then rather than what was your testimony at lines one through four is what you intend to utilize as the DCF multistage model?

A Correct.

Q Turn to page 26 of your testimony, please, sir.

A Yes.

Q There you show use of the CAPM model; is that right?

A Yes.

Q On page 27, at line five, you show the implementation of the model; is that right?

A Yes.
Q You used an 8% market risk premium and this was obtained from SBBI 1999 Yearbook, a page from which is shown in Exhibit MJB-6; is that also right?
A Yes.
Q Would you turn, please, to MJB-6?
A Yes.
Q The fourth number down the right hand column shows the 8% market risk premium; is that right?
A Correct.
Q You used a long-term bond yield in the DCF model. to be consistent with the 8% market risk premium why didn't you use the 5.4% long-term bond yield shown at the top of the exhibit?
A I plated to the most recent treasury bond data available from the Federal Reserve Board.
Q Then why didn't you use a current market risk premium rather than the historical 1926-1998 risk premium?
A The 1990--or 1926 to 1998 risk premium is calculated over a very long period of time

and is unlikely to show much fluctuation from one additional year. In fact, when you calculate risk premiums over a fairly short period of time they are subject to quite a bit more fluctuation. I believe Dr. Weaver used ten years, which not only would not pick up an entire business cycle but could be very subject to the use of one additional year of data. When you are using 75 years of data that is a more stable data setup and is unlikely to change from the addition of one additional year.

Q Would that 75 years data set include some major events such as wars?

A Definitely, and a depression.

Q And depression.

A And several business cycles which is why they call it long-run, and, probably more reflective, investor's expectations are based on long-run. And I felt that this was a better way to capture long-run expectations.

Q Dr. Blake, would you accept, subject to check, that had you used the 5.5% long-term bond yield the CAPM results would have been

9.8%?

A Subject to check.

Q I want to discuss for a moment the size premium shown in Exhibit MJB-6?

A Yes.

Q Is the size premium for regulated natural gas distribution companies or is it for all companies?

A I believe it is for all companies.

Q Does the fact that a company is regulated have any effect on its risk?

A Probably it does, yes.

Q And what would that effect be?

A It would probably reduce that risk.

Q Does the stage in a company--of a company's life cycle have any effect on its risk?

A Yes.

Q What would that effect be?

A Very new company, say, one year old, would probably be regarded as riskier than one that was more mature.

Q Would you agree that regulated companies tend to be mature companies while some non-regulated small companies might be mature but some might be relatively new and, therefore, more risky?

A This would be an average of all small caps out there and you are going to find some new and some mature.

Q So, there might be some higher risk and some lesser risk?

A That's included in that average, yes.

Q Would some non-regulated small companies be small because management has not successfully grown them?

A State that again please?

Q Would some non-regulated small companies be small because management has not been successful in growing them?

A Hard to tell why they are small. There may be a number of reasons why they are small, the niche that they are serving in the market place may not be a big one, there is many reasons why a company might be small.

Q Let me change gears. Dr. Blake, do you think that the risk of Delta and its cost of equity would be affected if the Commission adopted the Alternative Regulation Plan that Delta is proposing?

A No, I don't.

Q Why then should it be adopted?

A The reason that I say that it doesn't--that I don't think it would is that right now what Delta is proposing is a three year experimental plan. Investors determine the worth of an investment based on long-run expectations. As the DCF model illustrated, long-run expectations go out to infinity in the DCF model. Three years is a good deal short of infinity and I think that what you are capturing there is--and I believe Dr. Weaver mentioned this in his testimony, as well, that there is uncertainty among investors about will that cause them to over earn will it cause it to under earn, will there need to be changes in the ARP, will it be adopted permanently. So, until those questions are answered, I honestly don't think it will have much affect on Delta's equity. Ultimately, if it is adopted and if it is very successful it may, but investors will have three years to find out if the ARP

is adopted.
Q But then the Commission would not be enhancing the risk profile of the company by implementing the ARP?
A No, I think it could help, but we don't know that. That's why we--
Q It's way down the road is basically what you are saying?
A That's why we call it an experiment is because it may do some good, we think it will do some good and we think it is going to be a very good thing. The only way that we are going to find out for certain is to actually adopt it.
Q On page 26 of your testimony--
A Yes.
Q --you used a .55 for beta?
A Yes, I did.
Q <u>Value Line</u> expanded coverage shows a beta of .45, are you aware of that?
A I did not find Delta in the <u>Value Line</u> expanded coverage. I looked pretty hard for them and didn't find them.
Q Sometimes those things escape us.

A Well, it escaped me, I was working on the paper version.

MS. BLACKFORD:

May I approach?

CHAIRMAN HELTON:

Uh-huh.

A Thanks. Looks like 45--

Q I'm sorry, I didn't hear you, you said it looked liked 45?

A It's hard to tell, it is pretty blurred, but yes, I believe it is.

Q Do we need a clearer copy for you?

MR. WATT:

It doesn't matter because I can't find it.

A Yes.

Q All right, thank you. What effect would that have on your CAPM model?

A That would reduce the rate of return.

Q Dr. Blake, in looking through your multitude of accomplishments I saw there were many, many areas of qualification but I was unable to determine whether you had presented testimony determining the cost of equity

previously; have you done so?
A No, I have not.
MS. BLACKFORD:
Thank you. That's all of my questions.
CHAIRMAN HELTON:
Mr. Blake, could you recalculate, since there is a different beta, could you recalculate and tell us what your recommended ROE would be using the CAPM model?
A Sure.
CHAIRMAN HELTON:
Not right now.
A Not right now?
CHAIRMAN HELTON:
No.
A Okay. I can do that, not a problem. It won't take long I promise. What I come up with is, after the size adjustment is made, it would be 12.28% and before the size adjustment is made it would be 9.68%.
CHAIRMAN HELTON:
Thank you. Mr. Goff.

CROSS EXAMINATION

BY MR. GOFF:

Q Dr. Blake, my name is J. R. Goff and I'm going to ask you a few questions sir. In your analysis of Delta's required rate of equity, I mean, return on equity, you used information for the gas industry as a whole as reported by--for companies followed by Value Line and Edward D. Jones; is that correct?

A Yes, it was natural gas distribution companies, it wasn't--it didn't include combined companies or pipelines, it was just for natural gas distribution companies reported by Edward Jones.

Q Could you tell me why you did not narrow your analysis to include only companies that were comparable to Delta?

A As I pointed out in my rebuttal testimony, I think one of the problems in this case is there really aren't any companies comparable to Delta. When I was evaluating Dr. Weaver's panel I found substantial differences between the ones he used as being comparable to Delta and Delta Natural Gas. And I feel, as I pointed out in my rebuttal testimony, that the only way to make--to kind of salvage the results is to do an after the fact adjustment for those differences. So, I really don't think there are too many companies comparable to Delta. We're talking about a fairly rural, mountainous, service territory, one of the lowest equity ratios of any of the gas distribution companies reported, very--smaller than almost any of the companies reported. One of the smallest companies out there that was reported in that panel. So, I didn't find any really comparable companies. So, what I was comparing it to is industry averages.

Q You, I believe, are familiar with Dr. Weaver's testimony?

A Very, yes.

Q Dr. Weaver has posed a 50 basis point adjustment for added risk due to size, leverage, and the predominantly rural high space heating load customer base. I think you, however, have proposed an entire two percentage point adjustment to compensate for Delta's relatively high amount of leverage in its capital structure. Why do you believe that an adjustment of a full two percentage points is reasonable?

A The reason that I think two percentage points is reasonable is, again, to account for the significant difference in equity between Delta and the industry as a whole, and Delta and Dr. Weaver's panel. If you look at the exhibits that I included, the difference between Delta and, say, an average, an industry average, the industry average was about 43 1/2% based on that panel of gas distribution companies. Delta is in the neighborhood of 30% for 13 1/2% difference, a pretty sizeable difference in return on equity. Between Dr. Weaver's panel and Delta there are several different ways of measuring that. He has got several exhibits in his testimony and I looked them up in my testimony dealing with equity ratios, and pretty consistently came out in the neighborhood of a 10% difference in equity ratio, whether you include short-term debt, don't include short-term debt, it came out to about 10 percentage points. So, that gave us the quantity difference. Now, in attaching a--how many basis points does that--should be associated with each percentage point difference, I relied on published research by Brigham, Capenski and Aberwald. It was the only one that I found out there that hit that topic dead on target. And what they found is that for, kind of on the average, for each point of--each additional point of debt that was equated to about a 12 basis point difference, but they made--they pointed out in their article that that was not exactly a linear, you know, that there was quite a bit covered in that average. Near the top end the difference between 48 and 49% was about seven basis points. They said the difference between like 40 and 41% was about 15 basis points. Well, Delta is way below 40%, they are in the neighborhood of 30%. So, I felt that my use of 15 basis points, given where Delta's equity level was, was a very conservative estimate of that difference, multiplied the 15% by the 10% for Dr. Weaver and came up with about 150 basis point difference just on that one factor alone, the leverage premium. If you apply it to the 13 1/2% difference that I'm talking about between the industry average and Delta, it comes up more in the neighborhood of 200 basis points, about 2%. So, where mine is founded, I believe, and I think the difference between the two is--I feel that that is founded and published research and that the 50 basis point recommendation, or difference that Dr. Weaver is recommending, is unsupported, at least I didn't find any support for it.

Q If the Commission were to approve Delta's proposed ARP, would Delta also need the winter normalization adjustment to stabilize earnings?

A I believe that the ARP and the weather normalization would work well together because you had weather normalization taking account of some of that variability, the variability in the ARP would not be as great. The ARP alone would probably lead to, you know, bigger ARP adjustments because you

would be picking up weather as well. So, I think the use of both of those together would probably reduce the amount of variation picked up by each of those, as was mentioned earlier in testimony today. The weather normalization really focuses on variability due to weather, where the ARP is a bit broader than that.
Q You are saying that you think both of them would be necessary to stabilize the earnings?
A I think that the one that would do the best job of stabilizing earnings would be the ARP. The weather variability would reduce the variability to some extent, the ARP would reduce it further, but neither would totally eliminate the variations that you see. I think that if you put both of them in you are going to get a sense for how well each works and because the weather normalization would be picking up the weather differences, the amount that would be picked up through the ARP would be smaller.
Q Dr. Blake, some testimony earlier about Delta's financial condition had deteriorated,

I think the word used was "showed financial distress." That seems rather a serious condition, could you tell us why Delta, maybe in your opinion, has not hired any consultants or implemented any internal review to determine what steps it might need to take to rectify that problem?

A Personally, I think one way of remedying that is they need a higher level of earnings. The earnings right now are insufficient to pay their dividend in four out of the last five years. To me, that indicates a fairly low level of earnings. One thing that came out earlier today was the question, you know, why don't they just float some more equity. You know, say, hey, want to get your equity percent up, just float some more equity. Who is going to buy equity on a company that can't cover its current dividends. In addition, I mean, just think about that. If your earnings aren't sufficient right now to pay your current level of dividends, who is going to run out and buy all this equity when you put it on the street. And the second is

who is going to put it on the street. This gets to the part of the problem with small cap stocks from discussions with Mr. Jennings. They can't--they are having a very difficult time finding anybody to place equity for them. One entity that they used to place--that used to place equity for them went bankrupt, another won't handle them any more because they are too small. Okay. This is why I think that size adjustment is appropriate, that the small companies do have a very real problem in raising equity. And these returns, the earnings that they are generating off the returns they are allowed at the present time are not getting the job done. In my opinion, they are causing real financial distress for this company.
Q I'm not sure that answered the question.
A Let me try again.
Q Well, I'll not--I do not wish to follow that one up at this time. Dr. Blake, there was a lot of testimony about the use of a hypothetical capital structure. Are you aware of any instance where this Commission,

the Public Service Commission of Kentucky, has allowed a utility to use a hypothetical capital structure?

A I'm not sure, I think there is a water company case that we worked with that utilized a hypothetical capital structure, I'm not positive of that. As far as being aware of any, can I cite any, no, I cannot.

Q None that you are aware of that--the position that Delta is in that was allowed?

A No. And just speculating, part of the reason for that might be, again, that there aren't too many companies that are in the position that Delta is in. I think your other gas distribution companies are doing quite a bit better than that.

Q Let me refer you to your rebuttal testimony. In that testimony you stated that in response to--not response, but you allude to LG&E.

A That's a bad habit, isn't it?

Q Yes, LG&E's prior rate cases revenue requirement was based on applying overall weighted return to total capitalization. In those LG&E's prior rate cases, did capitalization exceed rate base?

A I don't know the answer to that. And I guess when you are taking a look at whether you should apply it to rate base or capitalization, in the grand scheme of things, it probably doesn't matter much as long as you are consistent with it. At times capitalization will be higher than rate base and other times rate base will be higher than capitalization. I guess what I've got a problem with is switching to whichever one is the lowest. As long as you are consistent, and my understanding is this Commission prior to Delta's last rate case, I understand that that was done in Delta's last rate case, but prior to that it had been applied to capitalization. When I was in New Mexico we applied it to rate base, but we consistently applied it to rate base, whichever, you know, what I find a bit problematic is switching back and forth to whichever one--at times capitalization will be higher, at times rate base will be higher. And I don't know in LG&E's past cases which was higher.

Q Were you involved in more than--how many of those LG&E rate cases were you involve in?
A I got in on the tail end of the last one, I caught the last month.
Q Would you agree, then, subject to check, that in Delta's prior rate case, 97-066, that the rate base exceeded capitalization?
A Subject to check. I don't know.
MR. GOFF:
You don't know. No further questions of this witness.
CHAIRMAN HELTON:
Redirect?
MR. WATT:
No questions Your Honor.
CHAIRMAN HELTON:
Additional?
MS. BLACKFORD:
Just a couple.

RECROSS EXAMINATION

BY MS. BLACKFORD:
Q You mentioned that the weather normalization adjustment factor and the ARP work side by side to

make for a smaller impact of each, if you will, that the rates, the net result of the rates, I presume, would be the combination of the two, but each would be smaller than it would otherwise be; is that right?

A Yes, and there is a possibility one may move one direction and one may move another.

Q Doesn't the ARP as proposed automatically account for weather entirely?

A If you take a look at the way it works, it would pick up weather as well. It would pick up all the variations.

Q So, if the ARP were adopted it would serve as an effective weather normalization adjustment, whether or not there was an explicit separate weather normalization adjustment?

A It would have that effect.

Q If the effects of weather on sales were eliminated in calculating the ARP, would the weather normalization adjustment or would the ARP have the greater effect on stabilizing earnings?

A Would you repeat that?

Q If the effects of weather on sales were eliminated in calculating the ARP, would the weather normalization adjustment or the ARP have the greater effect on stabilizing earnings?
A I believe the ARP would have a greater effect in stabilizing earnings.
Q Assuming the effects of weather on sales were eliminated?
A There are other factors picked up in the ARP.
MS. BLACKFORD:
Thank you. That's all my questions.
MR. WATT:
May I have one follow up Your Honor?
CHAIRMAN HELTON:
Yes.

REDIRECT EXAMINATION
BY MR. WATT:
Q Dr. Blake, under Delta's proposed Alternative Regulation Plan, the adjustments, if you will, because of changed conditions, occur annually; is that correct?
A That's my understanding.

Q How frequently do the adjustments occur for weather under the weather normalization adjustment?
A I believe those are monthly.
Q That being the case, isn't it true that the extent of an adjustment would be smaller using the weather normalization adjustment in conjunction with the Alternative Regulation Plan?
A Yes.
MR. WATT:
That's all I have, Your Honor.
CHAIRMAN HELTON:
You may be excused.
A Thank you.
MR. WATT:
Steve Seelye, Your Honor.
(WITNESS DULY SWORN)
MS. BLACKFORD:
May I inquire, I have somehow lost track of what was your Exhibit Number 1?
MR. WATT:
It was the Affidavits of Publication.

The witness, WILLIAM STEVEN SEELYE, having first been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. WATT:

Q Steve, would you please state your name for the record?
A William Steven Seelye.
Q Where do you live?
A My business address is 6711 Fallen Leaf, Louisville, Kentucky 40--I'm sorry--S-e-e-l-y-e, and my business address is 6711 Fallen Leaf, Louisville, Kentucky 40241.
Q And by whom are you employed?
A The Prime Group.
Q What is the purpose of your testimony in this proceeding?
A I address--in my direct testimony I address the Alt Reg plan and cost of service study, as well, in the rebuttal testimony I also address certain pro forma adjustments.
Q Have you filed direct testimony on behalf of Delta in this proceeding?
A Yes, I have.
Q Are there any changes, corrections, or

additions to that testimony?
A No.
Q If I asked you the questions contained in your direct testimony today, would you give the same answers?
A Yes, I would.
Q Have you filed rebuttal testimony on behalf of Delta?
A Yes, I have.
Q Are there any changes corrections or additions to your rebuttal testimony?
A Yes, one.
Q What is it?
A It's on page 16, line four, there is a--it says "n of i," it should be "one over n of i."
Q If I asked you the same questions contained in your rebuttal testimony today, subject to the correction that you just gave us, would you give the same answers?
A Yes, I would.
MR. WATT:
I have no further questions Your Honor. We would move the admission of his

direct and rebuttal testimony.

CHAIRMAN HELTON:

So ordered. Ms. Blackford?

CROSS EXAMINATION

BY MS. BLACKFORD:

Q Mr. Seelye, at page one of your original testimony.

A Yes, yes, ma'am.

Q You state that your background is in engineering and mathematics; is that right?

A Yes, and physics.

Q At page three, line two, you state that you testified before this Commission with regard to marginal costs of providing service; am I right?

A Yes.

Q Would that have been for an electric company?

A Yes.

Q Have you ever performed a marginal cost study of a gas distribution company?

A I've worked with marginal costs of gas--for gas utilities but not a full blown marginal cost study, no.

Q Would you agree that a gas distribution company is a prime example of the decreasing cost firm, that it is a company whose average cost of providing service decreased as the amount of service provided increases?
A No.
Q On what basis, then, do you think it is appropriate to have a single company as a provider of gas in an area?
A Typically, there are economics of scale. That doesn't mean that the marginal cost isn't higher than the embedded cost, which is implied by your question.
Q What do economies of scale indicate about the average cost of service?
A It is probably cheaper to have a single company than it is to have multiple companies. And if you had a very large utility, their cost would probably be lower.
Q Your study in this case and your exhibit--
A Could I elaborate on that last response? The distribution service would be, the gas service itself may or may not be because that is a different issue all together. I just

wanted to clarify what I was talking about was the distribution cost itself. There could be some economies of scale because you would--there would be fewer administrative services that you would provide per customer, therefore, cost could be lower for very large distribution companies.

Q Your study in this case, as shown in your exhibits, is an average embedded class cost of service study; is that right?

A Yes, you could use that term to characterize this study.

Q When you finished you had placed everyone of those total costs, actual cost of service, into several customer classes that you have identified?

A Yes, it is also referred to as a fully allocated embedded cost of service study, that is another way to characterize it.

Q And no portion of total cost is left unassociated with some customer class in such a study; is that right?

A It certainly wasn't our intention to do that, that's correct.

Q That is different from a marginal cost of service study where the sum of the marginal cost may add to more or less than whatever the total cost of service at a given point in time may be for a given company; right?
A That's correct.
Q On the Delta system, with the great preponderance of fixed cost, return, taxes on return, depreciations, is the short run marginal cost less than the average imbedded cost of providing service?
A No, not necessarily. Because the cost of hooking up--Delta's marginal cost would be driven by the cost of hooking up new service lines, new mains going to the customer, and those costs are on--are higher, typically, than the embedded cost. That is a part of the situation we have with Delta. Whenever they add cost, the capital cost, the investment cost goes up, therefore, their cost goes up. There was an exhibit that I submitted, or a schedule that I submitted, that showed that.
Q Right, but this question was actually directed to

the short-run cost of providing--
A Well, their short-term cost is probably analogous to their long-term cost. For--typically short-term cost--it depends on how you define short-term cost. A lot of times it is defined as assuming a fixed stock of energy using appliances. But in Delta's case what you have is a cost that is driven by hooking up a new customer. Now, that has a short-term effect unlike in an electric utility you have long-term cost that are--cost of generation capacity. You have a long planning cycle, therefore, it is a long-term cost. Two different concepts between the electric side, which you can take a long-term view, a different--you look at it a little differently.
Q Let me refer you to page three, line 18 of your testimony.
A Which testimony, there are three?
Q Your--oh, that would be your testimony in 176 in the general rate case.
A Now, which page again please?
Q Page three, line 18.

A Yes, ma'am.

Q There you state that the "Cost of service study can also be used to determine unit cost."

A I'm sorry, I probably have the wrong--I have the wrong one. Yes, ma'am.

Q All right, are you with me now?

A Yes, I believe so.

Q There you state that the "Cost of the service study can also be used to determine unit cost." Is that correct?

A Yes, ma'am.

Q Would you agree that if you take the total cost of some kind of service and relate it to, divide it by the number of units of service, the results you get is the average cost per unit of service?

A Yes.

Q Referring to page three of your testimony, what is the unit whose cost can be determined from your cost of service study?

A Okay, in--this actually refers to the approach that we took later in the testimony and it is two different units. One unit is-- the billing determinants which are used for each rate class. And the billing determinants are--the units are applied when you calculate the rates. There are two, one of them is customers, number of customers, the other one is MCF.

Q On Exhibit 5-1--I'll wait for you to get there rather than just jumping ahead.

A Yes, ma'am.

Q For residential customers your cost of service study shows the total customer related cost, including a portion of the cost related to distribution mains, net of miscellaneous revenues, is $8,488,823 on line 13, that is where that is shown; is that correct?

A Yes, ma'am.

Q And this is related to 32,940 residential customers, resulting unit cost is $21.48 per customer per month?

A Yes, ma'am.

Q Now, that would be the average cost per customer; is that right?

A Yes.

Q That's not the marginal cost per customer?

A No, definitely not.

Q Looking at this schedule am I correct that
you believe that most, some $4,885,000, of
customer costs is related to distribution
mains and not to things like services,
meters, house regulators, the reading of
meters, rendering of bills and keeping of
customers accounts?
A Yes, ma'am.
Q Referring to the unit customer cost that your
study shows, is the calculated customer cost of
$21.48 the cost of a unit of service?
A Could you repeat the question? I'm sorry, I
didn't hear a question in there?
Q Referring to the unit customer cost that your
study shows, is the calculated customer cost
of $21.48 the cost of a unit of service?
A It's the cost per customer, yes, per month.
Q But is it the cost of service, the cost of
being on the system or the cost of the
service?
A No, it's a cost of customer related cost per
customer, not the total cost of service
because there are demand and commodity
related costs that aren't reflected in that

number. We are not taking the total revenue requirements, if you will, or the total cost of service and dividing it by the customers. What we are doing is taking the customer related cost only and dividing it by the number of customers. Therefore, I can't characterize it as the total cost of service.

Q This may somewhat beg the obvious, but you don't claim that the Delta system is typified by customers who have connected to the system but who do not demand any other service, do not demand the provision of gas, demand only to be connected; is that right?

A That's true, but it is based on various usage patterns of customers. Not all customers have the same usage pattern. You may have a small customer that is being served or a large customer that is being served, but presumably all of the customers that are connected with the system desire some sort of gas service whether it is ongoing service, backup service, or some sort of service, yes.

Q So, when you say at page three of your testimony that you can determine from your study unit cost, in the case of customer cost that is not the service that a customer is demanding, rather because you don't have any customers who simply want to be there but don't at least want some sort of service at some point; is that right?

A I'm sorry I didn't understand the question.

Q When you say at page three of your testimony that you can determine from your study unit cost in the case of customer cost that is not simply existing on the system but rather includes the fact that they will receive service at some point, a gas service of some sort at some point?

A That is probably correct. It may--there may be a situation where a customer wants to be connected to the system that doesn't use any gas. That is unlikely, but the possibility exists. We--I have encountered that situation in a lot of different services and a lot of different rates were provided, sometimes customers do want backup service. Okay. Where they don't necessarily utilize the service on an ongoing basis, in a given year they may not utilize that service but they still want the backup service. So, that situation could exist. On Delta's system I think that situation is probably unlikely.

Q Well, let me refer you to page five of the same testimony, lines 21 through 22.

A Page five did you say?

Q Yes.

A And that was lines 21 and 22?

Q Yes.

A Okay, I am there.

Q Here you state that "Costs classified as demand related are costs related to facilities installed to meet peak usage requirements." Please define costs as that is used as a term in this testimony?

A Okay. In this testimony what costs will refer to are the costs of providing service, that is synonymous to revenue requirement, and what revenue requirement represents is depreciation, operation and maintenance expenses, income taxes, other taxes, I think that is basically it. There could be like ad valorem taxes, insurance, but it is basically revenue requirement for the customer. And what we are referring to here are those demand related costs or revenue requirements. Therefore, it is a synonymous term.

Q So, in your cost of service study all the distribution mains costs that you believe were demand related, 42%, you allocate on the basis of peak demand; is that correct?

A Yes, ma'am.

Q If you allocate all of the total demand related main cost on the basis of peak demands, is that consistent with your statement on page five of your testimony that the demand related costs are cost related to facilities that are installed to meet peak demands?

A No, because a certain portion of the cost is customer related, and those costs using the zero intercept analysis are customer related and that is a standard methodology for determining customer related costs. So, the only portion that we are talking about here are the demand related portion of those mains and--

Q We are on the same track now, I may not have used the word main related costs, but, yes, the question would be if I limited it to demand related, your answer would be yes; is that right?

A If--yes, yes.

MS. BLACKFORD:

Can Mr. Galligan approach with the book? He needs to show it to Mr. Watt first.

A This is a very old book isn't it? Looks like a song book. 1961. I had the honor of meeting or hearing him speak, the late Dr. Bonbright speak, he was quite a dynamic individual. Anyway, go ahead.

Q That is Dr. Bonbright's 1961 version of Principles of Utility Ratemaking, do you recognize this?

A Yes, I do, indeed.

Q Would you open that please to page 360 to 361, are you there?

A Yes.

Q At the top of those--at the pages the words fully distributed costs appear. This is the Bonbright chapter that deals with fully distributed costs; is that right?

A Okay, yes, I do see it.
Q In fact, the fully distributed cost chapter begins on page 337 and includes the materials on that page?
A Uh-huh.
Q Would you agree that your cost of service study is a fully distributed cost study?
A Yes.
Q Would you agree that the term fully distributed cost, when referring to a cost of service study, refers to the fact that all costs, total costs, will be fully distributed in the performance of the study; that is, that no cost will be left unallocated to some customer class. Is that right?
A Yes.
Q Please read the first paragraph of the Bonbright text, the fully distributed costs chapter on page 360?
A Okay. "So far, then,"--is that the one that begins there?
Q Yes.
A Make sure--"the argument supports the system-peak responsibility formula of capacity-cost

allocation. But the argument applies only to the allocation of incremental capacity cost--to the cost per kilowatt of enhancing the capacity rather than to the averages cost per kilowatt of total capacity." Okay, do you want me to read on?

Q No, that's fine.

A Okay.

Q Do you agree that unlike the Bonbright prescription, the peak responsibility method of cost application applies only to the incremental capacity cost. You have, in fact, in your proposed cost, allocated the total cost of which you believe to be capacity related cost of mains on the basis of class peak demands?

A Well, no, because the--of the costs that I've allocated as demand related costs, yes, but what--I'm not sure he makes the distinction between demand related costs here. I don't see that word in here.

Q Actually we were looking at incremental capacity costs.

A Yes, I'm not sure what that refers to without

going back and reading all of this, but I suspect, since it is talking about kilowatts, he is probably talking about production plant and that is what this refers to more so than distribution costs. But without reading a lot more, I can't tell you.
Q Thank you.
A Would you like to have your book back? I'd like to have this.
Q I've been trying to catch that book for years, though. Don't go far it will be grabbed, huh? The holy writ of utility rate making. All right. Exhibit 2-35 and 36 associated with your testimony, would you turn to those please?
A Yes, ma'am, which pages I'm sorry, two?
Q Two-35 and 36.
A Yes, ma'am.
Q There you show the allocation factors used to allocate demand related costs; is that right?
A Yes.
Q And there we see the DEM-01 and DEM-03 are identical; is that right?
A That's correct.

Q And DEM-04 and DEM-05 are equal except for the lower demands associated with off-system transportation customers having no DEM-04 or DEM-05 demand; is that right?
A Yes, ma'am.
Q Now, is it on Exhibit 3 where you show the derivation of the demands used to allocate various demand related costs?
A Yes, ma'am, I believe so, just a second, let me turn there and verify it.
Q All right.
A I trust that that is the case, yes.
Q And you used DEM-05 to allocate all which I believe are demand related mains cost; is that right?
A Yes, ma'am.
Q Please explain what design demand days are?
A The design--first of all, what we do is calculate the base load, plus the temperature sensitive load at the design day temperature of zero degrees. This methodology is consistent with the methodology that is laid out in the gas--I probably won't get this title correct, but the NARUC Gas Rate Design

Manual--one of those two manuals that they have essentially lays out this methodology for calculating.

Q Are you aware that FERC routinely, as a matter of policy, uses peak demand concept, a three day peak demand to allocate peak demand related costs?

A FERC, I'm not aware of any distribution utilities that FERC regulates. That may be the case, but, as far as I know, FERC or the Federal Energy Regulatory Commission out of--they regulate transmission systems and I'm unaware--there may be some distribution facilities but, primarily, what we are talking--what FERC issues cost of service policy on is transmission companies. I'm unaware of any distribution companies.

Q Okay. But as a matter of policy, they do use a peak demand concept of three day peak demand, are you aware of that?

A I'm not sure what they use today. I know that there has been a lot of different methodologies that they use and I'm not sure what their current policy is, if they have a

standard policy for all companies.
Q How would a three day peak demand compare to a design day demand methodology?
A I don't know, I haven't calculated that.
Q Would it be smaller, since design day occurs only once?
A It depends on the peak day; it depends on the peak day. If they had a zero degree--if they had, say, a minus five degree, a minus four degree and a minus three degree on a peak day, it would be the total sales and transportation peak day requirements would be higher. So, I can't say it would be lower, it depends on the peak days.
Q But your second and third day would necessarily be lower than your peak day or it would by definition not be a peak; is that right?
A Oh, okay, I see what you are saying. But would it be less than the design day peak day, I thought was your question, and I don't know the answer to that question. But you are saying would an average of the three top be lower than the average of the highest.

Unless they are the same, the mean value theorem in math would suggest that they would be lower.
Q Delta doesn't experience design day demands every year, does it?
A No, they do not.
Q So, your use of design day concept of peak demands produces higher demands for the weather sensitive customer classes than would the use of actual peak day or a three day concept of peak demand?
A Well, two comments about that. It is hard to say, depending on the year, okay, which gets back to the other one to answer your question. But the second comment is that Delta designs their system around the design day, they don't design it around the peak, therefore, that is the appropriate figure to use for allocation purposes. In addition to that, this is consistent with the NARUC Cost Allocation Manual--or not the Cost Allocation, Rate Design Manual.
Q I appreciate that thorough answer but is the answer yes or no?

A I believe it was yes, but would you repeat the question to make sure that we are clear?
Q If you use design day concept of peak demand, that produces higher demands for the weather sensitive customer classes than would the use of an actual peak day or the three day concept of peak demand?
A The answer is no. It depends--depends on the year you are in.
Q Assume that the actual peak day does not exceed the design day and answer the same question?
A Okay. And the question is is the total allocator lower, the total MCF lower? The answer is yes, presumably. Okay, I've got to even qualify that one because the design day is based upon the estimate of the temperature sensitive load and the base load, and the reality of it is that it may be higher or lower. So, again, I can't even answer affirmatively in that situation.
Q So, the design day is not all that accurate?
A The design day is what they base the system on. It may not reflect in a given year

exactly what the peak demand is. Okay? It is indeed an estimate, but it is what they design their system around.

Q Would you agree, factually, that if one were to use actual class peak demands instead of theoretical or calculated demand design days, that demand related costs would be allocated in accord with how the system was actually utilized on the peak day, rather than how the system might be used on a design day?

A If we are defining utilization as the demand that is placed on it, I would agree with that answer.

Q I'm sorry.

A If you are defining utilization as the demand that is placed on it on that day, I would agree that--I would answer that yes.

Q Would you look at Exhibit 2-36?

A Yes, ma'am.

Q There special contract customers are shown. If we take the annual volume shown on line one of 1,817,276 MCF and divide it by the 365 days in a year, we get 4,979. That appears on the DEM-01 and DEM-03 lines; correct?

A Yes, ma'am.
Q The same for off-system transportation customers--
A Yes, ma'am.
Q --appears, 1,404,111 MCF divided by 365 equals the 3,847 that is shown?
A Yes, ma'am.
Q And on Exhibit 3 for commercial/industrial transportation customers, if we take that 1,391,510 MCF annual volume, divide it by 365 days, we get what you would call that peak design day demand of 3,812; is that correct?
A I'm lost there, would you take me through that again.
Q On Exhibit 3.
A On Exhibit 3, okay.
Q Reference to commercial/industrial transportation customers--
A Yes.
Q --whose annual volume is 1,391,510 MCF and if it is divided by 365 days, their peak design day demand becomes 3,812; is that correct?
A Yes.
Q Am I factually correct that for each of the three

classes just examined your peak design day demand has been calculated to equal what that demand would be were these customers to take their annual demands for gas equally on each and every day of the year?

A That's the methodology that is used here, correct.

Q Am I correct that this calculation technique is known as the 100% load factor method?

A I've never heard this particular calculation being referred to as that. It does result-- the methodology that is used does result, I do believe, in 100% load factor for these particular customers. And the reason for that is in each case, for each class, we are treating it consistently. We are taking base load and we are treating them all the same, therefore, for each class there is a 100% load factor assumption with respect to the base load. Okay. The variation that is produced or the increment that is added is temperature sensitive load. Okay. That creates the differences. And the base load for these particular classes, since they are

not temperature sensitive, produces a 100% load factor. But it does as well for the other classes if you look at it a little harder.
Q So, you are assuming that these are 100% base load?
A This methodology produces that result.
Q Then no smaller demand could be ascribed to these customers that would be consistent with being able to take their annual demand?
A Pardon me?
Q Then no smaller demand could be ascribed to these customers that would be consistent with their being able to take their annual demand?
A Smaller than what?
Q In other words, they must take at 100%?
A Yeah, I've done cost of service studies worth less than 100%, or more than 100% load factor. So I can't agree with that. Take, for example, if you--this is--I'm getting into the electric cost of service study but the principle could apply. A lot of times you can have a coincidence factor that is such that they peak off-peak, for example.

Or if they are not right on the peak, therefore, they could have a higher than 100% load factor. That happens in the real world all the time.

Q Well, if they take at 100% load factor basis, their peak demands would be greater than you have calculated, is that correct, if they don't actually take at 100% peak factor?

A The question again?

Q If they don't actually take a 100% load factor, their peak demands would be greater than you have calculated, is that right?

A Yes, or if they had a higher than 100% load factor, it would be lower.

Q Would you look at Mr. Walker's testimony, page 11, lines one through three?

A Mr. Walker's testimony?

Q Yes.

A This is in the prefiled testimony in this case?

Q His prefiled testimony in Case--in the general rate case.

A Give me a second. Which page please? Okay, I'm there, I believe I'm there.

Q Are you there?

A I believe so.

Q You have utilized the assumption that the commercial/industrial interruptible transportation customers are--were described or calculated 3,812 MCF of peak demand in your study and that demand is based on 100% load factor. Would you please read into the record what Mr. Walker has said about the load factor of large commercial/industrial class customers?

A Which page, which line please?

Q That is page 11.

A Line?

Q Lines one through three?

A One through three, "The residential and small commercial customer classes have temperature normalized load factors at 23.0 and 24.2 percent respectively as compared to 31.9 percent for the large commercial/industrial class. However, while the customers within the residential and small commercial classes are relatively homogeneous, the large commercial/industrial class is extremely diverse with respect to customer size load factor."

Q So, the large customer industrial class was at 31.9%?

A That's what Mr. Walker says.

Q Is there any diversity in demand on any of Delta's service lines that run from its main to the customers premises?

A I would say there are probably always is diversity on the lines. It depends--

Q Now, I'm talking about service lines?

A Oh, to the customer's premises?

Q Uh-huh.

A Okay. Service line from the connection at the street, for example, to the house, there would not be diversity there.

Q So, since no two customers can share a service line, each customer needs one; is that a fairly obvious statement? And the service line has to be sized to meet that customer's gas usage requirements on the day of the customer's greatest gas demand; is that right?

A Yes.

Q Is there any diversity in demand on any of Delta's main system?
A I would say there is.
Q Is it a fair statement that your services have to be sized to meet each customer's peak demand but your main system has to be built to meet the maximum coincidental, either coincident peak system demand or coincident peak area demand?
A It--okay, I would agree with the first premise that the service line has to be sized for the customer's maximum demand. Now, would you repeat the second premise for me, please?
Q The second premise begins with the main system has to be built to meet the maximum coincidental either coincident peak system demand or coincident peak area demand?
A I--no, I can't agree with that exactly. In reality the main has to be sized to meet the maximum load served by that main.
Q You have used the zero intercept method to calculate what you believe is the customer component of the distribution mains; is that right?
A Yes, I have.

Q Conceptually, this is the cost associated with installing zero inch pipe; is that right?
A Yes.
Q Zero inch pipe is, of course, a hypothetical and there could never be a pipe cost for zero inch pipe because it doesn't exist, is that right?
A Yes.
Q Your estimating technique of determining the cost of zero inch pipe actually estimates the installed pipe, is that right?
A The installed pipe, yes.
Q The installed cost?
A Yes.
Q And embedded in your estimation of the cost of the distribution system of all zero inch pipe, you have included the cost of that pipe itself and, again, as it is a hypothetical, it simply doesn't exist; is that right?
A The zero inch pipe obviously doesn't exist.
Q So, embedded in your estimation of the cost of the distribution system of all zero inch pipe, you have included the cost of the pipe

itself at zero inches; is that correct?
A Yes.
Q On Exhibit 4-3 you have calculated that it takes Delta $3.14 to install one foot of zero inch pipe; is that right?
A Exhibit--I'm sorry?
Q 4-3?
A 4-3, what was the figure that you quoted again?
Q $3.14?
A Yes, that is correct.
Q Are you aware that Western Kentucky Gas Company has a simultaneous case pending on 97-070 before this Commission?
A Yes.
Q Are you aware that in their filing requirements FR10(9)(v) the estimated cost of installing zero inch pipe is 89 cents per foot?
A It could very well be.
MR. WATT:
I object, that's irrelevant.
Q Can you explain the enormous disparity in the cost?
A Oh, yes, I could--of course, there are lots

of factors that could explain that. I can't tell you exactly what they are but I could probably guess what they might be. The--this is driven--I've done a lot of these zero to intercept analysis, I've done them for electric utilities, I've done them for gas utilities, you get different results. It depends largely on things such as the age of the system. For example, if you have a newer system then rather than an older system you will get a different result here. Okay, another factor is that Delta is a rural utility, okay. That will--that could very well change it, they are a smaller utility, that could change it. But probably the factor that would drive it more than anything else is the relatively newness of the system. I haven't analyzed Western to see what their vintage of their average pipe is in the ground, but I would suspect that they probably have, based on that number you gave me, they probably have an older system.

Q All right, thank you. Does Delta have a hook-up policy?

A Pardon me?
Q Does Delta have a hook-up policy?
A Line extension policy, you mean, a main extension policy?
Q Uh-huh.
A Yes, I believe it does.
Q Does that policy preclude them from hooking up potential customers who really have no intention of using gas?
A It is my understanding of the policy that a customer must use some form of gas to receive service. And it could be a small service and they view it as an obligation to provide service to a customer that comes on the system. And it could be a small customer, it could be a large customer, and it could be a small residential customer, it could be a large residential customer.
Q Do you know if they ever hook up someone who merely wanted a gas cooking stove?
A I believe they would.
Q Or perhaps a blind for hunting birds where it would be used very, very infrequently?
A I think you probably should direct that question

to one of the company witnesses, but it is my understanding that they view their obligation to serve as an obligation to provide service to customers.

Q Would you refer again to the Bonbright book?

A I'll need it back.

Q Have we placed it at risk again by passing it around the table? Pages 348 through 349.

A I'm there.

Q The last paragraph starting on page 348, would you read that into the record?

A "But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in my opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But the fully distributed cost analyst dare not avail himself"--boy this is well written--" "but the fully distributed cost analyst dare not avail himself of this solution, since he is the prisoner of his own assumption that `the sum of the parts equals the whole.' He is therefore under the impelling pressure to `fudge' his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other cost categories."

Q Mr. Seelye, in your cost of service study have approximately 58% of the cost of distribution mains being dumped into the customer component of the service?

A Well, he speaks of a methodology that wasn't used here. He speaks of a minimum system approach, we did not use a minimum system approach. I was perfectly aware of Bonbright's exception to the minimum system approach. If I remember correctly, he doesn't speak of zero intercept approach in this study. It was probably not used frequently at that time. Let me look in the index here, I can probably--I see no reference to zero intercept.

Q For both the minimum--zero intercept and the minimum system attempt to measure customer costs; is that correct?

A Yes. I'd like to elaborate on it a little bit. It is hard to say what Dr. Bonbright would--his comments would be on the zero intercept and, unfortunately, we can't ask him now.

Q Just a second I need to switch off folks here. I always reach a stage in a hearing where paper has become a critical mass, and you are the lucky witness where this happened. Let's address year-end adjustment expenses for a moment.

A Yes, ma'am.

Q On page 32 of your rebuttal testimony you state that if Delta's customer base were to double, the company would have to hire new employees; is that right?

A Yes.

Q Would you accept, subject to check, the company currently has about 37,000 customers?

A Yes.

Q Were they to double you would be making the rather obvious assumption that it would be moving up to approximately 74,000 customers and the company would have to add employees; is that right?

A Yes.

Q Based on that kind of example, you conclude that there is correlation between the number of customers and the number of employees; am I correct?

A Yes, that was just to illustrate the point.

Q How long do you think it would take for a doubling to occur on Delta's system?

A At the current rate, probably, 12 years, somewhere in that ball park. I could probably calculate it.

Q So, you are talking about a post test year adjustment based on something perhaps 12 years down the road?

A To double?

Q With that assumption?

A To tell you the truth I don't think that the --there was any assumption here to double anything. This is--this point was merely to illustrate the point that if Delta doubled in size they would have to increase the number of customers. With customer growth--

MR. WATT:

Employees.

A Yes, let me restate that. If they were to double in size, they would have to increase the number of employees that are necessary to provide service. The--there is some increment all along the line. Okay. At any time when you add customers there is associated, just drawing a line and calculating marginally, like running a regression analysis against it, you would increase employees.

Q Would you accept, subject to check, that the proposed year-end customer adjustment amounts to the recognition of 1,059 additional customers over the actual test year average level of customers of 37,066 customers?

A Run that by me again.

Q Would you accept, subject to check, that the proposed year-end customer adjustment amounts to the recognition of 1,059 additional customers over the actual test year average level of customers of 37,066 customers?

A I would accept it, subject to check, yes.

Q Would you accept that this represents an increase expressed in percentage of approximately 2.86%?
A I'll accept that, subject to check.
MS. BLACKFORD:
Can you tell me what number we are on for exhibits, six or seven?
MR. WATT:
You marked six, but then you didn't move its admission, so I don't know how you want to deal with that.
MS. BLACKFORD:
All right, what we will do is--
MR. WATT:
Let's call it seven.
Q In the company's response to AG Number 67 in the ARP proceeding which is attached to this, you show the number of customers for Delta for the period between 1991 and 1998; is that correct?
A Yes, that is what that says.
Q This shows that the customers have grown from 30,269 in 1991 to 36,896 in 1998; is that correct?
A Yes, ma'am.
Q This represents a growth of approximately

6,627 customers representing a customer growth of 22%, would you accept that, subject to check?

A Yes, ma'am.

Q Now, the response to AG 42 in the ARP case, also attached, shows the number of employees, employed at Delta for the last ten years.

A Yes, ma'am.

Q Would you accept that the company's employees did not change during that ten years?

A Yes, that is consistent with Mr. Jennings' testimony that he had taken efforts to get the lean and mean, therefore, he has taken measures to keep his costs, employees cost down. So, that is consistent with what he said.

Q So, that this 22% increase in customers actually resulted in an employee level that went down?

A From the beginning to the end it stayed the same. It went down and it went back up, therefore, I would take this to mean that when he was getting lean and mean, it went down to 168 and now that he is growing it is going back up.

Q Your testimony that the number of employees will grow as a result of an increase in the customers, if there is only a 2.86% increase, is contrary to the actual employee customer ratio shown on this schedule, isn't it?

A Say that again, I'm sorry, you lost me.

Q Your testimony that the number of employees will grow as a result of an increase in the customers of only 2.86% is contrary to the actual employee customer ratio shown on this schedule?

A I believe in the future you could anticipate employee growth as a result of customer growth because they have tried to reduce the number of employees that they have. And you cannot draw any conclusions whatsoever from this because it was in a period of "right sizing," therefore, I don't think it illustrates anything.

Q Would you accept, subject to check, that the proposed revenue annualization in this case represents only .58% of the company's total pro forma consumption and revenues?

A I'm sorry, could you repeat the question?
Q Yes. Would you accept, subject to check, that the proposed revenue annualization in this case represents only .58% of the company's pro forma consumption and revenues?
A I'll accept that, subject to check. Could you repeat the percentage again, please, because it is--point zero--
Q .58%.
A That sounds high, could you demonstrate how that is calculated?
Q I'm not a witness.
A Oh, okay. I'll back up, I can't accept that subject to check then.
Q On page--I want to go to your rebuttal testimony if we are not already there, on page 48.
A Yes, ma'am.

CHAIRMAN HELTON:

Do you want to move this in?

MS. BLACKFORD:

Oh, I do want to move that in, that's seven.

CHAIRMAN HELTON:

So ordered.

(EXHIBIT SO MARKED: Attorney General Cross Examination Exhibit No. 7)

Q On page 48 of your rebuttal testimony you implied that the budgeted information to be included for purposes of establishing the AAC will include proper information because, as you state on lines seven through eight, the budgeted information used to calculate the AAC would be reviewed by the Commission; is that right?

A Yes, ma'am.

Q Let me hand you the PSC, your response to the--or the company's response to the PSC follow up request number six to the ARP. I'd like to have that marked for identification purposes as number eight, Attorney General Cross Exhibit Number 8.

A Yes, ma'am.

Q Am I correct that the last phrase of the sentence, the first responsive paragraph is, "We do not envision extensive review of the AAC filing?"

A Yes, this is a one year review, that's correct. This is not the three year review that we referred to--were referring to earlier.

Q And in the first bullet point you again note that the filing of the AAC the Commission would be allowed approximately 30 days between the filing and the implementation for review and any questions would be handled informally by phone conversations or by informal technical conferences; is that correct?

A Yes, that is correct, and that is consistent with a lot of other mechanisms that are filed with the Commission, including the gas supply cost recovery mechanism, the environmental cost recovery mechanisms, the DSM mechanisms, the performance based rate making mechanisms, therefore, it is a very consistent methodology for evaluating costs like this.

Q This refers to, essentially, total system cost not otherwise covered by special formats and each of those that you have referred to is a special format; is that correct?

A Yes. In many cases the cost may be higher than what we are dealing with here, though.

Q I want to talk a moment about bad debt expense. At pages 37 and 38 of your rebuttal testimony you criticize Mr. Henkes' uncollectible expense adjustment as being a post test year adjustment?
A Yes, ma'am.
Q An adjustment that goes beyond the end of the 1998 test year; is that right?
A Yes, ma'am.
Q First, Mr. Henkes has made his uncollectible expense normalization adjustment based on actual historic uncollectible expenses experience from 1993 through 1998. These are all years prior to or during the 1998 test year; is that not so?
A That's correct, but his logic for doing so was to look beyond the end of the test year, not to look at that period. If you look at that period there was--if you look at the five year period there was as growth, therefore, that would suggest an even higher debt level of expenses than what was utilized in the test period of the rate case. Therefore, in order to support his five year averaging he said that he would anticipate

bad debt expenses going down, in his opinion. And he justifies--that's the logic he uses to use a five year average looking at past costs.

Q But he does not rely on projected data for 1999 or 2000 to determine the expense normalization adjustment?

A No. If he used projected data you would have a higher debt--bad debt expense, not a lower one.

Q Are you generally familiar with the rebuttal testimony of Mr. Brown?

A Yes, I am.

Q In fact, you were present in the room when he was testifying concerning that rebuttal testimony?

A Yes, ma'am.

Q Are you aware that in his rebuttal testimony at pages four through five he has proposed an adjustment of--to adjust medical expenses based on actual and projected medical expense data?

A No, I don't think he has proposed to adjust--he put that exhibit together, put that analysis together to illustrate that there are a lot of other costs that have gone up. He--I don't think that Mr. Brown is proposing to use that adjustment in the case, only except if Mr. Henkes' isolated the look at certain costs.

Q But in making his exhibits he did, in fact, look at the expenses that extended beyond the historic and went into the future; is that correct?

A But not for the test year adjustments in the case, that is just an analysis he performed in--to rebut Mr. Henkes.

Q Are you aware that in 1998 the company's uncollectible expenses have reached a very high level of $346,000 representing almost 1% of the company's revenues?

A I haven't performed that calculation, but I'll accept that.

Q Subject to check?

A Subject to check.

MR. WATT:

I object, subject to check, to the characterization of very high level. We

can accept subject to check that number--
A The number is what I was accepting, subject to check.
Q Let me rephrase that. Would you accept, subject to check, that it has reached $346,000 and that that represents approximately 1% of the company's revenues?
A I'll accept that, subject to check.
Q Would you accept, subject to check, that this is the highest level ever reached in the company?
A I haven't looked at that, so I can't--I have no basis to even accept it subject to check.
Q On page 38 of your rebuttal testimony you state that there has been an upward trend in uncollectibles and you suggest that there is nothing to indicate that this trend will change?
A Yes.
Q Are you aware that the company has, in fact, implemented a policy for apparently working harder to collect the uncollectible?
A Policy is probably--listening to Mr. Brown's discussion earlier today, a policy is

probably not the correct way to describe that. It is an enhanced effort to be diligent in getting bad debt expenses down.

Q Let me pass out what will be marked for identification as number eight--

CHAIRMAN HELTON:

No, you need to move eight into the record.

MS. BLACKFORD:

Oh, I do need to move eight, I will do so.

CHAIRMAN HELTON:

So ordered.

(EXHIBIT SO MARKED: Attorney General Cross Examination Exhibit No. 8)

Q Have you reviewed the question and the response?

A Yes.

Q And the question asked, essentially, for an explanation of why collected revenues averaged nearly what, 40% higher--my math is not that good--in the first seven months of 1999 over what was occurring in 1998, and the response was that the company made a conscious effort to aggressively enforce the company's collection policies.

A Yes, ma'am.

Q And it actually reduced bad debt expense for the year and increased collection revenue?

A Uh-huh.

Q This then is a reversal of the trend.

A There may be several reversals that you haven't looked at though. You look at one particular item here and say that there is a reversal, but there could be other costs that have gone up beyond the end of the test year.

Q But in saying that there was nothing, you are ignoring that crucial fact; is that correct? That at least known fact that there is an aggressive policy now to reduce uncollectible?

A That's what this says.

Q Let's talk a moment about prior rate case expenses.

A Yes, ma'am.

Q Is it your position that if the company was allowed to amortize its rate case expenses over three years, but the rates effective period of the case in which this allowance

was made is only two years, then the company
has under recovered its rate case expense?
Would you like me to say that again, I kind
of stumbled in the middle which may have
caused a loss of thought?
A Sure.
Q Is it your position that if the company was
allowed to amortize its rate case expenses over
three years with the rates effective period in
which this allowance was made is only two years,
then the company has unrecovered its rate case
expenses?
A Well, that depends on how it is treated in
the subsequent case. If it were subsequently
disallowed, as proposed by Mr. Henkes, then
they would not be allowed to recover the rate
case expenses.
Q Let's assume the converse, that the company was
allowed to amortize its rate case expense over
three years but the effective period for the rate
is five years, under that same logic, has the
company over recovered rate case expenses?
A Well, I think you are misconstruing the
purpose of rate making. The purpose of rate

making is to base rates perspectively on costs that are represented in the test year. Okay. The--therefore, I can't agree with it. The methodology that the Commission uses to handle extraordinary items such as this, and there are several and I've seen them in several cases where there may be an extraordinary expense set up as an amortization, and that amortization is set up in the rate base. The utility set that--typically, will set those costs up as an amortized expense and amortize it on their books, therefore, it will be in subsequent rate cases if that is when it happens to occur. That is the methodology that has been used by the Commission that is consistent with a lot of other adjustments that are made.

Q So, you don't agree that the company should defer these rate over-recoveries and in its next rate case credit the ratepayers with these deferred rate case expense over-recoveries?

A I don't think anybody has made that

recommendation. That was--what you just described was not Mr. Henkes' recommendation.
Q You are aware that the ARP is intended to interreact with the rate case as filed; is that correct?
A It--what we--the rate case would establish base rates and the Alt Reg Plan would implement--would be implemented off of that if that is what you are saying?
Q And the rates would include O&M expenses awarded in this case; is that correct?
A I could accept that.
Q The rates to which ultimately the ARP multiplier would apply?
A Let me reword it and see if this is acceptable. The rates will reflect the operation or maintenance expenses that are accepted for test year levels.
Q And those operation and maintenance expenses that are acceptable continue to be the basis upon which rates are adjusted under the ARP; is that right?
A Yes.
Q Now, the duration of the experimental plan is

three years; is that right?
A Yes, ma'am.
Q And so, that would include two years past what would be the end recovery of the last year of the 97-066 rate recovery; is that right?
A I don't think so, I think it will match exactly, won't it? Hasn't it been two years since the last rate case and that was a five year amortization, we are two years into that, therefore, two plus three is five.
Q You're right; you're right. Should it continue past that three years it would then go beyond, right?
A Yes.
Q Please refer to page seven of your direct testimony.
A Which direct testimony?
Q Your direct testimony in the general rate case, 176?
A Page five?
Q Seven.
A Seven, I'm sorry. Yes, ma'am.
Q There you discuss performance based cost controls represented by the indexed O&M

expenses?

A No, on this page I discuss the cost allocation used. This--

Q I'm sorry, I'm referring you to the wrong testimony, it is the ARP direct, I guess. That would be the testimony in 97-046.

A I hate to do this, but which page did you refer to?

CHAIRMAN HELTON:

Seven.

A Seven, okay, I'm there, I believe I'm there.

Q I think we are all there. It does, in fact, talk about performance based controls; is that correct?

A Yes, it does.

Q There you discuss the controls represented by the indexed O&M expenses; is that right?

A Yes, ma'am.

Q On lines 18 through 21 you state that the indexed O&M expense to which actual O&M expenses will be compared under the proposed ARP consists of the annual O&M expense per customer, as approved in the last base rate case, increased for changes in the CPI-U for each year since the last case; is that right?

A That's not what I see on page seven, line 18. What you read sounds correct, but I don't see that on page seven.

Q The first controls of performance based rate making measure--

A Okay, I'm there.

Q --that would compare Delta's non-gas supply O&M--

A Yes.

Q --expenses per customer--

A Okay.

Q --to the non-gas O&M expenses on a per customer basis approved in Delta's last rate case, after adjusting for changes in the consumer price index for urban consumers, the CPI-U since that rate case?

A Yes, ma'am.

Q Can you please refer to the first page of the Company's--now, would you please turn to the proposed tariff schedule for the experimental ARP under the topic Performance Based Cost Controls?

A I assume you mean sheet number 33?

Q Yes.
A Okay, I'm there.
Q There the indexed O&M expenses are defined as the non-gas O&M expenses approved by the Commission in the company's most recent adjustment of general rates after adjusting for changes in the CPI-U; is that right?
A Yes, ma'am.
Q Would you please refer to the first page of the Company's ARP filing, the letter filing, of February 5, 1999, and under that filing--let me read you the first paragraph under the heading Background and Purpose of this Filing. "Delta Natural Gas, Inc., Delta, is proposing an Alternative Rate Regulation Plan on an experimental basis for a period of three years. At the end of the three years experimental period the program will be evaluated in order to determine whether the Alternative Regulation Plan should continue beyond the initial period." This is again repeated on page 21 of the same filing under the heading Proposed Implementation Schedule. There it says, if you would like to turn and

follow, considering I'm getting tongue tied and may be misquoting something. "Delta proposes that the alternative rate making mechanism would go into effect with final meter readings on and after July 1, 1999, and continue for an experimental period of three years."

A Yes, ma'am.

Q "At the end of the three year experimental period the program will be evaluated in order to determine whether the alternative ratemaking mechanism should continue beyond the initial period," is that right?

A Yes, ma'am.

Q When the proposed plan states that after three years the program will be evaluated to determine if the ARP should continue this doesn't say that there will be any general rate case associated with the evaluation; is that right?

A It does not say that here.

Q If the ARP were to be implemented by the Public Service Commission at this time the statement may also mean, if one hypothetically assumes the evaluation is positive, that the ARP program would continue another three years without a general base rate case; is that correct?

A No. We have subsequently addressed this issue in data responses or responses to data requests and that is not what it says--intended at all now. This particular filing did not address that issue. The Commission has asked certain questions to get at that point and in response to those questions--ultimately, it would be up to the Commission to determine if base rates would be set or not. But it was assumed that there would be a redetermination of base rates after the end of the three years in subsequent data responses.

Q So, this is an assumption based on a modification of the filing as made?

A I wouldn't call it modification of the filing because that issue is addressed in the filing. It is responses to interrogatories that flushed out certain issues, just like we are flushing out certain issues in this proceeding today.

Q I understand, but tariffs don't contain, for

instance, a three year sunset provision, it
would require such a rate?

A Yes, it wouldn't have to be changed if the
Commission decided not to. So, I don't think
it is appropriate necessarily to put it in
the tariff.

Q Would you accept, subject to check, that
neither the filing, the tariffs, nor the data
responses indicate that there will be a
general rate filing at the close of three
years

A That there will absolutely be one?

Q Uh-huh.

A Just a second, let me look. Here is what it
says in one of the data requests, the
responses to one of the data requests. And
this is Delta's response to the PSC's Order
of June 4, 1999. It says, "The scope of the
three year review will largely depend on the
Commission and the intervenors. It is
anticipated that the scope of review will
encompass the following: Developing an
application of the AAC, AAF, BAF; impact of
the mechanism on individual customer classes;

rate of return range utilized in the mechanism"--which implies base rate adjustment--"non-gas supply costs recoverable through the rate mechanism base rate adjustment; analysis of performance based controls; analysis of utilities non-gas supply cost; analysis of cost of service and rate design."

Q While you identify certain elements, nowhere in there does it say that there will be a base rate adjustment does it, or a base rate case?

A It doesn't use those terms but it is certainly implied.

Q On your rebuttal testimony at pages 45 through 46, if you would like to turn there before we move ahead.

A Yes, ma'am.

Q On page 45, starting at line 17, you state that the analysis contained in the testimonies of Mr. Henkes and Catlin is that their analysis considered an indexed O&M period expense of five years; is that correct?

A Yes, ma'am.

Q And on page 46, lines four through six, you stated, quoting, and I quote, "However, under Delta's proposed Alt Reg Plan the O&M expenses reflected in base rates would be reestablished every three years." Is that correct?
A Yes, ma'am.
Q All right, thank you. On the one hand your testimony in the proposed ARP tariff sheet clearly state that the indexed O&M expenses will use the annual O&M expenses approved by the PSC in the last general rate proceeding as a starting point and then be increased by the change in the CPI-U for each year after this general base case. The filing also states that after three years the program will be evaluated to see if it continues or not and there is no mention whatsoever that the evaluation process will take place as a part of a general base case. Yet you accuse the AG witnesses of fatal flaws because the company--it now is the company's position that O&M expenses might be examined in a three year proceeding; is that correct?
A Yes, that is correct and I still believe it

is correct.

Q In doing your zero intercept calculations you used a weighted regression to estimate the zero intercept; is that right?

A Yes, ma'am.

Q Have you ever reviewed Dr. Estomin's testimony in this proceeding?

A Yes, ma'am.

Q In your rebuttal testimony you spend about 18 pages addressing the issue of the appropriate weights to use in the weighted regression.

A Yes, ma'am.

Q Are you aware that Dr. Estomin is not recommending reliance on a weighted regression?

A Yes, ma'am, I even refer to that.

Q Dr. Estomin, however, recommends the use of an unweighted regression if a zero intercept approach is to be relied upon; is that your understanding?

MR. WATT:

Objection, calls for speculation as to what Mr. Estomin wants to do.

CHAIRMAN HELTON:

Rephrase the question, please.

Q Were we to assume that Dr. Estomin is recommending the use of an unweighted regression, if a zero intercept approach is to be relied upon--I'm sorry, my brain quit on me. Let's assume that Dr. Estomin is recommending the use of an unweighted regression if a zero intercept approach is to be relied upon. Do you recall the example that Dr. Estomin presented using Delta's data and the data of a hypothetical company with an identical system except for the quantity of two inch steel pipe?

A Yes, I believe.

Q Based on your review of that example, would you agree that the weighted regression results are highly sensitive to the number of feet in each category?

A I'm sorry, could you rephrase the question?

Q Would you agree that the weighted regression results are highly sensitive to the number of feet in each category?

A A weighted regression approach will be sensitive to the number of feet in each category, that is correct.

Q Is there any intuitive reason, aside from the arithmetic of the regression logarithm, why the cost of a zero capacity system should be over 14% different based solely on a change in the number of feet of two inch steel main such as that shown in Dr. Estomin's hypothetical?
A Yes, because you should give appropriate weight to the amount of feet in each category.
Q Please describe the data that underlie the zero intercept analysis that you performed--analysis that you performed?
A Okay. The data consists of average unit cost data for each type of pipe on Delta's system. And what that represents is the total cost for each type and size of pipe divided by the number of units for each size and pipe, the respective number of units, and that provides the average unit cost. And in that situation it is appropriate to use weighted regression. If you actually use--if you actually had the actual cost data for each span or each foot of pipe that is installed on the system, it

wouldn't be necessary, but since you are dealing with average data it is necessary to weight it. That is standard information or standard approaches that are used in the statistics, the statistics literature.

Q Over what period of time did these data span?

A A number of years, I can't say exactly how many years, but for quite a number of years.

Q Are there any adjustments made to the cost data to reflect the differences in vintage?

A No.

CHAIRMAN HELTON:

Could we take a break, please, I think we need to take a break.

MS. BLACKFORD:

Surely.

CHAIRMAN HELTON:

We'll take a short break.

(OFF THE RECORD)

CHAIRMAN HELTON:

Back on the record, Ms. Blackford.

MS. BLACKFORD:

Yes. I need to move in Exhibit Number 9

CHAIRMAN HELTON:

So ordered.

(EXHIBIT SO MARKED: Attorney General Cross Examination Exhibit No. 9)

Q And, Mr. Seelye, may I get you to turn to page 24, lines two through seven, of your rebuttal testimony?

A Yes, ma'am.

Q Why did you include the quoted material from the Gas Distribution Rate Design Manual at that point in that testimony?

A Okay. The reason I put this in here it says--because of the sentence that says, "The distribution plant investment in mains may be classified as both demand and customer related." Okay, that sentence in particular I felt was important because of the cost of service studies submitted by Mr. Galligan didn't classify cost as demand and customer, classified them as demand and commodity. And the point I was making here is that the manual suggests demand and customer.

Q That it suggests demand and customer, may I--that is, in fact, the 1989 NARUC Manual?

A Yes.

Q And that recitation is from page 22 of the manual?

A Thirty-two is what it says.

Q Thirty-two of the manual.

A That's what it says in my quotation.

Q All right, thank you. I'm going to mark this as Cross Exhibit Number 10 for purpose of identification. This is a copy of portions of the NARUC Manual which includes, I believe, page 32.

A It does not include page 32, mine does not.

Q I believe it does, it is just two pages in from the back.

A Oh, okay, they are not in sequential?

Q Not quiet sequential.

A Okay.

Q Are you with me?

A Yes, ma'am.

Q All right. Would you flip back two pages prior to that to what is page 32 of that 1989 manual, and am I correct--

CHAIRMAN HELTON:

Page 30?

Q Page 30.
A Yes, ma'am.
Q And pointing out that the quote that you have made for purposes of saying that this is what the manual recommends is merely what the manual recommends in the context of the illustrative embedded cost service study that it happens to be laying out at that point. Not that that is the appropriate methodology or the favorite methodology, merely that it is "a" methodology, the illustration of which is being laid out in the manual at that point?
A Okay. I don't believe that is correct because what I'm quoting here is a generic statement or a general statement that addresses what--how distribution plant investment may be classified. I--it is not in the context of the zero intercept methodology, that statement is not, it is a general statement.
Q Let's go back then to page 30 which is where that general statement flows from and read the first paragraph.
A Okay.

Q The first paragraph provides, "A cost of service study is a series of choices regarding potentially controversial methods of identifying and allocating costs incurred by a utility. This illustrative study represents one possible means of computing class cost of service. There are many other equally correct methods." Have I correctly read that?
A Yes.
Q And would you turn with me, please, back towards the front, one more page, which take us to page 22 of the NARUC Manual?
A Yes, ma'am.
Q And there, in fact, it is talking about classifications of cost.
A Yes, ma'am.
Q And it speaks of customer costs under subsection (a).
A Yes, ma'am.
Q And the first paragraph there says, "Customer costs are those operating capital costs found to vary directly with the number of customers served rather than with the amount of utility service

supplied. They include the expenses of metering, reading, billing, collecting, and accounting, as well as those costs associated with the capital investment in metering equipment and in customers' service connections." The next paragraph, "A portion of the costs associated with the distribution system may be included as customer costs. However, the inclusion of such costs can be controversial. One argument for inclusion of distribution related items in the customer cost classification is a `zero or minimum size main theory.'" Have I read that correctly?

A Yes, ma'am.

Q Does that tend to indicate that the inclusion of distribution costs as a customer cost can, in fact, be controversial and that there may be accepted methodologies which do not include such an allocation?

A Okay. I agree first that it can be controversial, the fact that it is being argued in that case--in this case illustrates that. The second point is that there are--it does say there can be different methodologies can be accepted for doing that, or it implies that concept. I don't disagree the different methodologies are correct--excuse me, I do not disagree that different methodologies have been used. In my opinion, the one that is utilized in this case is correct and the Commission has accepted that methodology in the past, therefore, we are relying on prior practice, therefore, greater weight should be given to that methodology.

Q That wasn't my question. My question is, does the NARUC Manual recognize that there are a variety of methodologies that are equally useful. And, in fact, does it not demonstrate that the quote that you have given is merely part of an illustrative study and not one that gives specific weight or favoritism to that as a means of allocation?

A Okay. I--in my previous response I was agreeing with that, but I was elaborating on my response.

Q I see, thank you. All right, I'd like to go back one sentence and note that you say that nowhere in the NARUC Manual does the allocation methodology utilized by Mr.

Galligan appear, the average in peak demand method that he has utilized?

A Okay. He has utilized the methodology that takes 50%--arbitrarily assigns 50% as demand and 50% as commodity. That methodology is not prescribed in this manual.

Q And doesn't his methodology, in fact, put it all into demand and then divide demand between annual usage, which is average usage, according to the footnote in his testimony, and peak?

A No. His methodology classifies--you are confusing two different processes in the cost of service study. The first process is to functionally assign, the second process is to classify costs as either demand related or customer related. Mr. Galligan arbitrarily classifies 50% of the cost--of mains related costs as demand and 50% as commodity. He does not first put them in demand and then reclassify them, he classifies them. That is my understanding of Mr. Galligan's testimony.

Q I'm sure you will take that up with Mr. Galligan in cross, but my point being that certainly an average in peak demand method is recognized by the NARUC Manual; is that correct?

A Mr. Galligan does not use average and peak methods. He uses a 50/50 split, which is arbitrary.

Q Are you familiar with Administrative Case Number 297?

A Yes.

Q The investigation--

A I attended the hearings.

Q --of the impact of the federal policy on natural gas to Kentucky customers, consumers and suppliers?

A Yes, ma'am.

Q Are you aware that on page 47 of the June `87 Order issued by the Commission in connection with that hearing, the Commission indicated its concern about cost of service methodologies that place all emphasis on maximum design day as a way to allocate cost, stating that this method may result in inappropriate shift of cost to the residential customer class and for that reason stated that cost of service methodology should give

consideration to volume of use?
A I can't remember that being in there but I'll accept that it says that.
Q You'll accept it?
A Yes, if I can elaborate on it a little bit, we haven't done that. We've allocated a portion--or classified a portion on the basis of demand and a portion on the basis of customers and then there was another portion assigned on the basis of commodity. So--winter commodity. So, we did not allocate all the cost on the basis of demand, we didn't use a methodology that the concern was expressed.
Q The design day demand does not allocate based on peak usage?
A We didn't allocate all costs on that basis. We allocated a portion on the basis of demand or design day.
Q The bills that were included in the demand segment?
A Those that were classified as demand, but all of them weren't--that doesn't encompass all the costs.

Q The costs that were not encompassed by that are the ones that are put in with customer service?

A Yes, there were fixed costs that--to answer it a little differently. There were fixed costs that were allocated on the basis of customer related, and there were fixed costs that were allocated on the basis of design day--excuse me, winter season volumes. So, unless I'm misunderstanding what was said there, I don't think that they express concern with the methodology that we used. In fact, the Commission has accepted this methodology that is used on a number of occasions in at least two cases. They have accepted the methodology that is employed here.

Q And are you aware that the Commission also in Admin 297 indicated that a variety of methodologies had been put forth, that a variety were considered appropriate, and that each company was to search for the cost of service methodology that was most appropriate to it?

MR. WATT:

What page?

MS. BLACKFORD:

That would be at--again, I think it is page 46, I'll be glad to present you copies of this if you would like to see it, I think 47.

MR. WATT:

That's okay, 47.

A Could I see it please?

Q I was trying to avoid one more hand out but I'm not getting there. Let me mark this for purposes of identification as Cross Examination Exhibit 11. Please take your time to review that, if you would like.

A I will. I reviewed the quotation that you read.

Q And have I correctly quoted that there are significant differences among class A, LDCs, that merit case by case decisions on cost of service methodologies?

A It says here, "There are a variety of techniques available for cost of service studies. The Commission acknowledge that there is not a single acceptable method to prepare such a study. Each LDC is encouraged to choose a methodology it finds appropriate." Now, I would have to believe that what the Commission meant by this is to follow principles of cost causation; otherwise, you end up in a state of gross relativism, anything goes. Therefore, I think it is important to utilize a methodology that is sound and that reflects cost causation on the system.

MS. BLACKFORD:

Thank you. I would move that what has been identified as Exhibits Number 10 and Number 11 be moved into the record.

CHAIRMAN HELTON:

So ordered.

(EXHIBITS SO MARKED: Attorney General Cross Examination Exhibits Numbered 10 and 11)

MS. BLACKFORD:

Thank you, that's all.

CHAIRMAN HELTON:

I've already conferred with Mr. Wuetcher. It seems that he has what we think would be considerable cross so we are going to adjourn until in the morning, 9:00.

(OFF THE RECORD)

CERTIFICATE

STATE OF KENTUCKY )
COUNTY OF FRANKLIN)

I, VIVIAN A. LEWIS, a Notary Public in and for the state and county aforesaid, do hereby certify that the foregoing testimony was taken by me at the time and place and for the purpose previously stated in the caption; that the witnesses were duly sworn before giving testimony; that said testimony was first taken down in shorthand by me and later transcribed, under my direction, and that the foregoing is, to the best of my ability, a true, correct and complete record of all testimony in the above styled cause of action.

WITNESS my hand and seal of office at Frankfort, Kentucky, on this the 8th day of November, 1999.

Vivian A. Lewis

VIVIAN A. LEWIS
Notary Public
Kentucky State-at-Large

My commission expires: 7-23-01

Vivian A. Lewis
COURT REPORTER - PUBLIC STENOGRAPHER
101 COUNTRY LANE
FRANKFORT, KENTUCKY 40601

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To purchase a copy of this transcript, please call the phone number listed on the bottom of the cover sheet.

| | Ratio | Cost | Weighted Cost |
|---|---|---|---|
| Common Equity | 29.8% | 11.90% | 3.5462 |
| Long-term debt | 60.17% | 7.48 | 4.5007 |
| Short-Term debt | 10.02% | 5.41 | 0.5421 |
| | | | 8.589% |

| | Ratio | Cost | Weighted Cost |
|---|---|---|---|
| Common Equity | 43.50 % | 10.413% | 4.5298 |
| Long-Term Debt | 48.43 % | 7.48 | 3.6226 |
| Short-Term Debt | 8.07 % | 5.41 | 0.4366 |
| | | | 8.589 |

Delta
EXHIBIT NO. 2
V. LEWIS

Delta 2

ERRATA SHEET

Comes Robert J. Henkes and makes the following corrections to his testimony:

1. On the title page, the word "OT" should be replaced with "OF".

2. On page 8, line 13 of the testimony, the word "increase" should be replaced with "adjust".

3. On page 17, line 3 of the testimony, the word "has" should be replaced with "had".

4. On page 21, line 1 of the testimony, the initial "C." should be replaced with "D.".

5. On page 24, line 16 of the testimony, the words "in this time" should be replaced with "of this case.

6. On page 29, line 5 of the testimony, the word "contract" should be replaced with "contrast".

7. On page 34, line 3 of the testimony, the word "to" should be added following the word "amount".

Done this the ___ day of September, 1999.

Robert J. Henkes

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

| | | |
|---|---|---|
| An Adjustment of Rates of | ) | Case No. 99-176 |
| Delta Natural Gas Company, Inc. | ) | |

ATTORNEY GENERAL

CROSS EXHIBIT ___/___

A. G. Cross
EXHIBIT NO. 1
V. LEWIS

Cross Examination Exhibit

**Delta Natural Gas Company, Inc.**

## Imputed Capitalization

31-Dec-98

| Type | Ratio | Cost | Weighted Cost |
|---|---|---|---|
| Common Equity | 43.50% | 11.90% | 5.18% |
| Long-term Debt | 48.43% | 7.48% | 3.62% |
| Short-term Debt | 8.07% | 5.41% | 0.44% |
| | 100.00% | | 9.24% |

## Capitalization as Adjusted

31-Dec-98

| Type | Ratio | Cost | Weighted Cost |
|---|---|---|---|
| Common Equity | 29.80% | 14.08% | 4.20% |
| Long-term Debt | 60.17% | 7.48% | 4.50% |
| Short-term Debt | 10.02% | 5.41% | 0.54% |
| | 100.00% | | 9.24% |

Notes:

1. Capitalization ratios from FR# 6-h, Schedule 9. Also from Blake, Direct Testimony, page 28, lines 10 & 11.

2. Capital cost rates from Hall, Direct Testimony, page 5, lines 12 - 21. Also, Blake, Direct Testimony, Pages 27 & 28.

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

| | | |
|---|---|---|
| An Adjustment of Rates of<br>Delta Natural Gas Company, Inc. | )<br>) | Case No. 99-176 |

ATTORNEY GENERAL

CROSS EXHIBIT 2

A.G. Cross
EXHIBIT NO. 2
V. LEWIS

## DELTA NATURAL GAS COMPANY INC
## CASE NO. 99-176

## ATTORNEY GENERAL'S INITIAL REQUEST FOR INFORMATION

53. With regard to A/C 1.926.03 Employee 401 ( k ) Plan expenses, please provide a workpaper showing exactly what the basis is for these expenses and how they were calculated. In addition, explain the large increase that the 1998 test year expense of $180,370 represents over the expense levels incurred in 1995, 1996 and 1997.

Response:

Delta's Employee 401K Plan expenses are calculated based on an employee's election to defer 2% to 15% of their salary. This is the employee's basic compensation as of July 1st. The employer will contribute a matching contribution equal to 50% of the employees salary deferral contribution up to a deferral of 5% of the basic compensation. The maximum matching contribution by the Company is 2.5%.

The increase in expense level is due to the increase in the maximum matching contribution by the Company, a reclassification of the Pension expense due to an account distribution correction made for a Trustee fee for 1997, increase in salaries, and percentage changes made by participants.

Sponsoring Witness:

John Brown

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

22. With regard to the response to AG-53, please indicate what the $180,370 1998 expense for 401(k) would have been with the elimination of the "reclassification of the Pension expense due to an account distribution correction made for a trustee for 1997".

RESPONSE:

The 1998 expense for 401(k) would have been $161,634 with the elimination of the "reclassification of the Pension expense due to an account distribution correction for a trustee fee for 1997".

Sponsoring Witness:

John Brown

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

| | | |
|---|---|---|
| An Adjustment of Rates of<br>Delta Natural Gas Company, Inc. | )<br>) | Case No. 99-176 |

A.G. Cross
EXHIBIT NO. 3
V. LEWIS

ATTORNEY GENERAL

CROSS EXHIBIT 3

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 99-176

ATTORNEY GENERAL'S DATA REQUEST DATED 8/11/99

55. With regard to the response to PSC data request Item 30 (Uncollectibles), please provide the following information

   a. For each year listed, provide the Total Revenues underlying the percentages on line 6 and indicate whether these Total Revenues include GCR revenues.

   b. Are uncollectibles related to GCR revenues collected via the GCR mechanism or through base rates?

   c. Page 325 of the Company's 1998 FERC. Form 2 shows that for 1998 and 1997 the uncollectibles were $345,870 and $310,000, respectively. Do these amounts represent accruals (provisions) or actual net write-offs? In addition, reconcile these two amounts to the uncollectible data for 1998 and 1997 on Item 30.

   d. Explain the reasons why the provision percentage of 73% for the 1998 test year is so much higher than the provision percentages for the prior 5 years.

RESPONSE:

See Attached

WITNESS:

John Brown

Delta Natural Gas Company, Inc.
Uncollectibles
Case No. 99-176
AG 55

A Resubmission of AG Item 30 Dated - 7/15/99*
ANALYSIS OF ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS

| LINE NO. | | 1993 | 1994 | 1995 | 1996 | 1997 | TEST YEAR |
|---|---|---|---|---|---|---|---|
| 1. | Beginning Balance | 213,918 | 165,503 | 52,907 | 98,033 | 82,094 | 83,647 |
| 2. | Charge Offs | (175,873) | (242,192) | (109,263) | (196,041) | (349,853) | (321,377) |
| 3. | Recoveries | 26,658 | 28,796 | 25,989 | 30,102 | 41,406 | 47,633 |
| 4. | Current Year Provision | 100,800 | 100,800 | 128,400 | 150,000 | 310,000 | 345,870 |
| 5. | Ending Balance | 165,503 | 52,907 | 98,033 | 82,094 | 83,647 | 155,773 |
| 6. | Percent of Provision To Total Revenue | 0.36% | 0.33% | 0.45% | 0.45% | 0.79% | 0.99% |
| 7. | Total Revenue | 27,726,216 | 30,972,260 | 28,845,368 | 33,052,029 | 39,185,262 | 34,857,742 |

*From Financial Statements - 12mo ended Dec. on Statement of Income*

8. *These amounts include GCR Revenues*

55 - B

9. Uncollectibles are reflected through the base rates.

55 - C

10. The FERC Form No. 2 shows accruals (provisions). These amounts agree with the corrected Item 30 shown above.

55 - D

11. The increase of provision to total revenues is due in part to a cyclical trend. The fluctuations in the ratio of provision to revenue is reliant upon economic trends and factors.

*On the original Item 30, the amount shown as current year provision was only the automatic journal entry to record the allowance as budgeted. Additional reserve was needed in these years, which was erroneously netted with the charge offs in the analysis submitted earlier.

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

| | | |
|---|---|---|
| An Adjustment of Rates of | ) | Case No. 99-176 |
| Delta Natural Gas Company, Inc. | ) | |

ATTORNEY GENERAL

CROSS EXHIBIT 4

A.G. Cross
EXHIBIT NO. 4
V. LEWIS

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year Ending |
|---|---|---|---|
| ta Natural Gas Company, Inc. | [X] An Original<br>[ ] A Resubmission | 03/31/99 | Dec 31, 98 |

## GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

| Line No | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| 235 | 904 Uncollectible Accounts | 345,870 | 310,000 |
| 236 | 905 Miscellaneous Customer Accounts Expenses | | |
| 237 | TOTAL Customer Accounts Expenses (Total of lines 232 thru 236) | 1,255,812 | 1,243,813 |
| 238 | 6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES | | |
| 239 | Operation | | |
| 240 | 907 Supervision | | |
| 241 | 908 Customer Assistance Expenses | | |
| 242 | 909 Informational and Instructional Expenses | | |
| 243 | 910 Miscellaneous Customer Service and Informational Expenses | | |
| 244 | TOTAL Customer Service and Information Expenses (Total of lines 240 thru 243) | | |
| 245 | 7. SALES EXPENSES | | |
| 246 | Operation | | |
| 247 | 911 Supervision | | |
| 248 | 912 Demonstrating and Selling Expenses | | |
| | 913 Advertising Expenses | 10,775 | 15,669 |
| 250 | 916 Miscellaneous Sales Expenses | | |
| 251 | TOTAL Sales Expenses (Total of lines 247 thru 250) | 10,775 | 15,669 |
| 252 | 8. ADMINISTRATIVE AND GENERAL EXPENSES | | |
| 253 | Operation | | |
| 254 | 920 Administrative and General Salaries & T/E | 2,096,502 | 2,027,447 |
| 255 | 921 Office Supplies and Expenses | 553,711 | 510,511 |
| 256 | (Less) 922 Administrative Expenses Transferred-Credit | ( 4,159,439) | (3,407,988) |
| 257 | 923 Outside Services Employed | 343,948 | 309,586 |
| 258 | 924 Property Insurance | 419,058 | 447,103 |
| 259 | 925 Injuries and Damages | | |
| 260 | 926 Employee Pensions and Benefits | 1,815,233 | 1,981,745 |
| 261 | 927 Franchise Requirements | | |
| 262 | 928 Regulatory Commission Expenses | 104,940 | 62,853 |
| 263 | (Less) 929 Duplicate Charges-Credit | | |
| 264 | 930.1 General Advertising Expenses | | |
| 265 | 930.2 Miscellaneous General Expenses | 440,458 | 435,302 |
| 266 | 931 Rents | | |
| 267 | TOTAL Operation (Total of lines 254 thru 266) | 1,614,411 | 2,366,559 |
| 68 | Maintenance | | |
| 269 | 935 Maintenance of General Plant | 139,966 | 187,132 |
| 270 | TOTAL Administrative and General Expenses (Total of lines 267 and 269) | 1,754,377 | 2,553,691 |
| 271 | TOTAL Gas O&M Expenses (Total of lines 97,177,201,229,237,244,251, and 270) | 22,875,094 | 28,243,568 |

(Next page is 328)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year of Report |
|---|---|---|---|
| DELTA NATURAL GAS COMPANY, INC | (1) [X] An Original<br>(2) [ ] A Resubmission | 03/31/98 | Dec. 31, 1997 |

## GAS OPERATION AND MAINTENANCE EXPENSES (Continued)

| Line No. | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| 238 | 6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES | | |
| 239 | Operation | | |
| 240 | 907 Supervision | | |
| 241 | 908 Customer Assistance Expenses | | |
| 242 | 909 Informational and Instructional Expenses | | |
| 243 | 910 Miscellaneous Customer Service and Informational Expenses | | |
| 244 | TOTAL Customer Service and Information Expenses *(Lines 240 thru 243)* | | |
| 245 | 7. SALES EXPENSES | | |
| 246 | Operation | | |
| 247 | 911 Supervision | | |
| 248 | 912 Demonstrating and Selling Expenses | | |
| 249 | 913 Advertising Expenses | 15,669 | 18,562 |
| 250 | 916 Miscellaneous Sales Expenses | | |
| 251 | TOTAL Sales Expenses *(Enter Total of lines 247 thru 250)* | 15,669 | 18,562 |
| 252 | 8. ADMINISTRATIVE AND GENERAL EXPENSES | | |
| 253 | Operation | | |
| 254 | 920 Administrative and General Salaries & T/E | 2,027,447 | 1,933,842 |
| 255 | 921 Office Supplies and Expenses | 510,511 | 524,632 |
| 256 | (Less) (922) Administrative Expenses Transferred—Cr. | [3,407,988] | [2,329,077] |
| 257 | 923 Outside Services Employed | 309,586 | 451,622 |
| 258 | 924 Property Insurance | 447,103 | 466,248 |
| 259 | 925 Injuries and Damages | | |
| 260 | 926 Employee Pensions and Benefits | 1,981,745 | 2,162,286 |
| 261 | 927 Franchise Requirements | | |
| 262 | 928 Regulatory Commission Expenses | 62,853 | 63,755 |
| 263 | (Less) (929) Duplicate Charges—Cr. | | |
| 264 | 930.1 General Advertising Expenses | | |
| 265 | 930.2 Miscellaneous General Expenses | 435,302 | 502,320 |
| 266 | 931 Rents | | |
| 267 | TOTAL Operation *(Enter Total of lines 254 thru 266)* | 2,366,559 | 3,775,628 |
| 268 | Maintenance | | |
| 269 | 935 Maintenance of General Plant | 187,132 | 123,402 |
| 270 | TOTAL Administrative and General Exp *(Total of lines 267 and 269)* | 2,553,691 | 3,899,030 |
| 271 | TOTAL Gas O. and M. Exp *(Lines 97, 177, 201, 229, 237, 244, 251, and 270)* | 28,243,568 | 23,230,298 |

## NUMBER OF GAS DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.
3. The number of employees assignable to the gas department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the gas department from joint functions.

| | | |
|---|---|---|
| 1. | Payroll Period Ended (Date) | 12-31-97 |
| 2. | Total Regular Full-Time Employees | 181 |
| 3. | Total Part-Time and Temporary Employees | 8 |
| 4. | Total Employees | 189 |

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 99-176

ATTORNEY GENERAL'S DATA REQUEST DATED 8/11/99

49. Please provide a breakdown of the expense components making up the Acct. 928 - regulatory commission expenses of $104,940 for the 1998 test year.

RESPONSE:

See Attached

WITNESS:

John Brown

Item 49

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 99-176
For the 12 Months Ended 12-31-98

| Line No. | | | |
|---|---|---|---|
| 1 | 1/31/1998 | DOT Pipeline Safety Program for 1998 | 20,870 |
| 2 | 1/31/1998 | Prepayments write off for Ky State Treasurer | 4,050 |
| 3 | 2/28/1998 | Prepayments write off for Ky State Treasurer | 4,050 |
| 4 | 3/31/1998 | Prepayments write off for Ky State Treasurer | 4,050 |
| 5 | 4/30/1998 | Prepayments write off for Ky State Treasurer | 4,050 |
| 6 | 5/31/1998 | Prepayments write off for Ky State Treasurer | 4,050 |
| 7 | 6/30/1998 | Prepayments write off for Ky State Treasurer | 4,050 |
| 8 | 7/31/1998 | Prepayments write off for Ky State Treasurer | 5,961 |
| 9 | 8/31/1998 | Prepayments write off for Ky State Treasurer | 5,970 |
| 10 | 9/30/1998 | Prepayments write off for Ky State Treasurer | 5,970 |
| 11 | 10/31/199 | Prepayments write off for Ky State Treasurer | 5,970 |
| 12 | 11/30/199 | Prepayments write off for Ky State Treasurer | 5,970 |
| 13 | 12/31/199 | DOT Pipeline Safety Program for 1998 | 23,960 |
| 14 | 12/31/199 | Prepayments write off for Ky State Treasurer | 5,970 |
| 15 | | **TOTAL ACCOUNT 1.928** | **104,940** |
| 16 | | | |
| 17 | | | |
| 18 | | | |
| 19 | | | |
| 20 | | | |
| 21 | | | |

## *Delta Natural Gas Company, Inc.*

Case No. 99-176
Item 47
Explanation of Major Variances

As pointed out in Item 47, several expense accounts have increased significantly compared to prior year. Although these accounts have a unfavorable variance, there are also accounts where expenses have been conserved. The following accounts are significantly below the previous year's amount:

| | | |
|---|---|---|
| 1.900.01 | Transp & Dist Payroll | 14,336 |
| 1.903.01 | Cashiering Payroll | 49,292 |
| 1.900.03 | Small Tools & Work Equipment | 29,379 |
| 1.880.04 | Fees Training Schools | 37,263 |
| 1.930.01 | Director Fees & Expense | 18,250 |
| 1.921.01 | Adm Telephone | 10,037 |
| 1.921.05 | Small Supply Items | 11,377 |
| 1.921.23 | Travel Etc Co Bus Oper & Const | 13,344 |
| 1.924.00 | Insurance | 28,046 |
| 1.932.01 | Mnt Communication Equipment | 17,754 |
| 1.932.03 | Mnt General Structures | 19,307 |
| 1.480.03 | Payroll Taxes | 14,466 |
| | | 262,851 |

### Explanation of Unfavorable Variances

1.856.00 – Right of Way Clearing

In, 1997 $55,000 was budgeted. Through cost saving efforts only $30,466.95 was spent. In 1998, $70,000 was budgeted, $20,000 additional to remove trees on the right of way downed as a result of the winter snow storm. The damage was not as bad as anticipated, therefore we spent only $54,869.19, which is very close to what is budgeted each year. As previously stated, 1997 was well below the normal amount.

1.880.05 – Uniforms

The amount in the 1.880.05 account is representative of the yearly uniform expenses. 1997 was an unusually low year. The 1996 amount was $45,166.22

1.881.02 – Rent & Land Rights

In January 1997, there is a credit of 11,380, which comes from correcting the account distribution from a transaction in the previous calendar year. Thus, the activity in the account for the year is negative. 1998 expense is normal.

1.900.02 – Opr Transportation Expense

The amounts booked are an average transportation rate based on payroll and transportation. Payroll costs increase therefore increasing expense in this account.

1.903.02 – Customer Collections & Records

Delta paid more to the US Postal Service for postage on its meter.

1.904.00 – Uncollectable Accounts

Uncollectible accounts are part of a cyclical trend that increase or decrease based upon certain economic trends and factors.

1.928.00 – Regulatory Commission Expense

Increase in PSC assessment and increase in revenues of Delta. DOT assessment of $23,960 applicable to 1999 was paid in the calendar year 1998.

1.930.02 – Company Memberships

Certain membership dues cover two years, or because of timing might occur in one calendar year and not the next. This is the case with the Southern Gas Association. $5,300 was paid in 1998, but not 1997.

1.930.08 – Stockholder Reports

Increase in cost of printing annual reports of $5,200 per year. Increase in ADP Investor Services of $6,000. Also, in calendar 1997, the cost of the annual shareholder's meeting of $11,048 was placed in the wrong account, understating 1.930.08 for 1997. Also in 1997, $34,944 of rate case expense was removed from this account and reclassified. This understates 1.923.04 for 1997.

1.921.06 – Miscellaneous Other Items

1.921.06 increased primarily in 1998 because amortization of previous rate case and management audit expense began in December 1997. The increase in 1998 affecting this account was $80,100.

1.923.01 – Outside Legal Services

We believe that the yearly total reasonably represents future expense expected in this account. 1997 expenses were lower than normal. In 1996, this account had total costs of $110,584. 1998's costs incurred are $37,459 less than those in 1996.

1.923.04 – Outside Services Other

A large part of the variance is for the Columbia Customer Group that Delta belongs to. Instead of membership dues the group bills out its expenses to its members. Sometimes the billings happen twice in a year and sometimes they go a year without billing. In 1997, The Group did not bill its members. Therefore, in 1998, the account had more activity than in 1997.

1.408.02 – Property Taxes

Property taxes increased due to the addition of plant, which increases Delta's property assessment.

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

| | | |
|---|---|---|
| An Adjustment of Rates of<br>Delta Natural Gas Company, Inc. | )<br>) | Case No. 99-176 |

ATTORNEY GENERAL

CROSS EXHIBIT 5

A.G. Cross
EXHIBIT NO. 5
V. LEWIS

Delta Natural Gas Company, Inc.
Case No. 99-176

AG DATA REQUEST
Dated 9/4/99

23. The 1998 Trial Balance shows that Delta's 1998 test year expenses include $729,269 for pension expenses. In this regard, please provide the following information:

   a. In the response to PSC data request 44, the Company provided its most recent actuarial report for pensions dated April 1, 1999. Please provide the pension expenses (equivalent to the 1998 reported pension expenses of $729,269) based on the data contained in this latest actuarial report and indicate how this pension expense amount was derived from the data in the report.

   b. Please explain the status of the Company's pension plan (in terms of either being overfunded or underfunded) for each of the last 5 years 1994 through 1998 and, in addition, explain why the pension balance is currently prepaid.

RESPONSE:

The AG has quoted an incorrect amount in this question. Delta's pension expense is recorded in account 1.926.02 Pension. This account for the test year was $292,817.96. The amount referred to in the question (729,269) happens to be expense in account 1.926.04 for the year.

   a. The net periodic pension expense per the actuary is $181,167 for the year ended 4/1/1999. This amount is provided in information from the actuary separately from the "actuary report" and is attached.

   b. Funding status:

| | Excess of assets over obligations |
|---|---|
| 1998 | 1,892,369 |
| 1997 | 489,893 |
| 1996 | 447,469 |
| 1995 | 92,989 |
| 1994 | (628,196) |

The pension balance is currently prepaid because the required contributions to the plan per IRS rules have exceeded the net periodic pension expense required by the actuary.

WITNESS: John Brown

**Delta Natural Gas Company, Inc. Retirement Plan**
**Statement of Financial Accounting Standards No. 87**
**For Fiscal Year Ending 4/1/1999**

## ASSUMPTIONS

| | 04/01/98 | 04/01/99 |
|---|---|---|
| Discount Rate | 7.00% | 6.50% |
| Expected Long Term Rate of Return | 8.00% | 8.00% |
| Rate of Increase in Compensation | 4.00% | 4.00% |
| Average Remaining Future Service | 15 Years | 15 |
| Measurement Date | 04/01/98 | 04/01/99 |

## FUNDED STATUS

| | ACTUAL 04/01/98 | FOR FISCAL 04/01/98 | PROJECTED 04/01/99 | ACTUAL 04/01/99 |
|---|---|---|---|---|
| Projected Benefit Obligation | (6,745,269.05) | | (7,678,053.48) | (8,286,368.36) |
| Plan Assets at Fair Value | 8,637,638.79 | | 9,962,373.69 | 9,188,450.03 |
| Funded Status | 1,892,369.74 | | 2,284,320.21 | 902,083.67 |
| Unrecognized Net Obligation or (Asset) Existing at Transition | (169,576.60) | | (127,182.46) | (127,182.46) |
| Unrecognized Prior Service Cost | 0.00 | | 0.00 | 0.00 |
| Unrecognized Net (Gain) or Loss | (869,910.35) | | (869,500.59) | 512,735.95 |
| (Accrued) or Prepaid Pension Cost | 852,882.79 | | 1,287,637.16 | 1,287,637.16 |

## NET PERIODIC PENSION EXPENSE

| | |
|---|---|
| Service Cost | 467,416.79 |
| Interest Cost | 471,938.84 |
| Expected Return on Assets | 715,385.10 |
| Amortization of: | |
| Unrecognized Net Obligation or (Asset) Existing at Transition | (42,394.14) |
| Unrecognized Prior Service Cost | 0.00 |
| Unrecognized Net (Gain) or Loss | (409.76) |
| Net Pension Expense (Income) at 4/1/1999 | 181,166.83 |

## RECONCILIATION

| | | |
|---|---|---|
| (Accrued) / Prepaid Pension Cost at | 04/01/98 | 852,882.79 |
| Net Periodic Pension Expense (Income) | | 181,166.63 |
| Company Contributions | | 615,921.00 |
| (Accrued) / Prepaid Pension Cost at | 04/01/99 | 1,287,637.16 |

Accumulated Benefit Obligation as of 4/1/1999

| | |
|---|---|
| Vested | 5,924,221.18 |
| Non-Vested | 33,733.14 |
| Total | 5,957,954.32 |

## DELTA'S ANNUAL PENSION EXPENSES

| | Acct. 926.02 |
|---|---|
| 1993 | $413,207 |
| 1994 | $435,425 |
| 1995 | $362,889 |
| 1996 | $347,221 |
| 1997 | $327,437 |
| 1998 | $292,818 |

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

PSC DATA REQUEST DATED AUGUST 11, 1999

44. Refer to page 19 of the 1998 Annual Report provided in Item 34 of the application.

a. Delta provides a non-contributory pension plan that covers all of its eligible employees. During the test period, did Delta make any contributions to the employee pension plan?

b. Provide a copy of Delta's most recent actuarial report concerning its employee pension plan.

c. Delta reported an accrued pension asset of $852,883 as of June 31, 1998. Provide Delta's December 31, 1998 accrued pension asset balance.

d. Provide a detailed explanation of why Delta did not propose to reduce its rate base by the balance in its accrued pension assets.

RESPONSE:

a. Yes, $720,640 in 3/98.

b. See attached

c. $717,283

d. Delta has not historically included prepaid (accrued) pension cost as a rate base item. If this were done at 12/31/98, it would be an addition to rate base, as the balance is currently a prepaid, or debit balance.

Sponsoring Witness:

John Brown

DELTA NATURAL GAS COMPANY, INC. RETIREMENT PLAN

ACTUARIAL VALUATION
AND
CONTRIBUTION STATEMENT

April 1, 1999

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

| | | |
|---|---|---|
| An Adjustment of Rates of | ) | Case No. 99-176 |
| Delta Natural Gas Company, Inc. | ) | |

ATTORNEY GENERAL

CROSS EXHIBIT 6

A.G. Cross
EXHIBIT NO. 6
ID ONLY
V. LEWIS

**DELTA CASE 99-176**
**MEDICAL EXPENSE ANALYSIS**

| | Medical Expense | Payroll | Med. Exp % Payroll |
|---|---|---|---|
| 1993 | $633,726 | $5,529,795 | 11.46% |
| 1994 | $794,865 | $5,785,303 | 13.74% |
| 1995 | $765,064 | $5,536,819 | 13.82% |
| 1996 | $719,274 | $5,781,054 | 12.44% |
| 1997 | $889,796 | $6,403,661 | 13.90% |
| 1998 | $729,269 | $6,251,888 | 11.66% |
| Average | | | 12.84% |
| Gross Annualized Payroll | | | $6,274,614 |
| Pro Forma Medical Expenses | | | $805,442 |

Pro Forma Medical Expenses Currently Reflected:

| | |
|---|---|
| Actual 1998 Test Year | $729,269 |
| Stop Loss Adjustment | 77,561 |
| Total | $806,830 |

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

| | | |
|---|---|---|
| An Adjustment of Rates of | ) | Case No. 99-176 |
| Delta Natural Gas Company, Inc. | ) | |

ATTORNEY GENERAL

CROSS EXHIBIT 7

A. G. Cross
EXHIBIT NO. 7
V. LEWIS

67. Please provide the number of customers, by customer class, at the end of each year from 1989 to present.

RESPONSE:

See attached.

WITNESS: John Hall

AG-67

Delta Natural Gas Company

Average Number Customers Fiscal Year - 1991-1998

| Year | Resisdential | Commercial | Small Comm | Total Comm | Industrial | Total |
|---|---|---|---|---|---|---|
| 1991 | 26,073 | 4,132 | | 4,132 | 64 | 30,269 |
| 1992 | 26,700 | 4,182 | | 4,182 | 70 | 30,952 |
| 1993 | 27,474 | 4,246 | | 4,246 | 70 | 31,790 |
| 1994 | 28,221 | 4,347 | | 4,347 | 77 | 32,645 |
| 1995 | 29,054 | 4,418 | | 4,418 | 73 | 33,545 |
| 1996 | 29,969 | 4,554 | | 4,554 | 73 | 34,596 |
| 1997 | 31,104 | 4,764 | | 4,764 | 73 | 35,941 |
| 1998 | 31,953 | 2,381 | 2,492 | 4,873 | 70 | 36,896 |

42. For each of the last 10 years (through 1998), provide the actual non-gas O & M cost per employee for Delta and provide the average compound annual growth rate during this 10-year period.

RESPONSE:

See attached.

WITNESS: John Hall

Delta Natrual Gas Company, Inc.
Operation and Maintenance Expense per Employee
for the years 1989 through 1998

AG 42

| | Operations | Maintenance | Total O&M | # of Employees | O&M per Employee |
|---|---|---|---|---|---|
| 1989 | 5,929,095 | 593,573 | 6,522,668 | 181 | 36,037 |
| 1990 | 6,580,418 | 552,729 | 7,133,147 | 184 | 38,767 |
| 1991 | 6,495,729 | 534,623 | 7,030,352 | 186 | 37,798 |
| 1992 | 7,393,444 | 524,976 | 7,918,420 | 182 | 43,508 |
| 1993 | 7,400,487 | 436,455 | 7,836,942 | 176 | 44,528 |
| 1994 | 7,786,185 | 408,505 | 8,194,690 | 172 | 47,644 |
| 1995 | 7,394,186 | 471,392 | 7,865,578 | 168 | 46,819 |
| 1996 | 7,991,451 | 525,715 | 8,517,166 | 172 | 49,518 |
| 1997 | 7,965,992 | 544,242 | 8,510,234 | 181 | 47,018 |
| 1998 | 8,188,080 | 585,411 | 8,773,491 | 181 | 48,472 |

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

| | | |
|---|---|---|
| An Adjustment of Rates of<br>Delta Natural Gas Company, Inc. | )<br>) | Case No. 99-176 |

ATTORNEY GENERAL

CROSS EXHIBIT 8

A.G. Cross
EXHIBIT NO. 8
V. LEWIS

6. Refer to Delta's Response to the Commission's Order of June 4, 1999, Item 11.

   a. Describe the review process that would be available to the Commission.

   b. What time limitations, if any, would be placed on conducting the review under the proposed mechanism?

RESPONSE:

a. & b.

Under the proposed plan, Delta would make an annual filing of the Annual Adjustment Component (AAC) based on budgeted information 30 days prior to the fiscal year beginning July 1 of each year. Because this filing is based on budgeted data and fully reconciled with actual historical costs through the application of the Annual Adjustment Factor (AAF) the following year, we do not envision an extensive review of the AAC filing.

As filed, the AAF would be implemented on October 1 of each year based on the actual results for the fiscal year ended June 30. Since it takes time to close the books for the year and prepare the filing, Delta could have the filing ready for submittal by approximately August 15, which would provide a period of 45 days to review the actual historical costs for the fiscal year.

The Balancing Adjustment Factor (BAF) merely acts as a true-up of volumetric differences in the application of the AAF and prior BAFs. Therefore, no additional cost information will be filed in connection with the BAF. As filed, the BAF would be implemented on January 1 and Delta would submit the filing 30 days prior to that date. Because the BAF is simply a true-up to reflect volumetric differences in application of the AAF and prior BAFs, Delta believes that 30 days should provide adequate time for reviewing this component.

Although we do not want to dismiss the importance of the AAC and BAF, in our opinion it is more important to implement appropriate procedures to evaluate the implementation of the AAF than the other two components of the mechanism. Because the AAF is based on actual historical costs, adjusted for the performance measures, and is used to reconcile the application of the AAC for the fiscal year, the AAF is the more important component. With respect to the procedures for the three components, we recommend the following:

- For the filing of the AAC, the Commission would be allowed to review the budgeted costs for the upcoming fiscal year during the 30 days between Delta's filing and the implementation of the AAC. Any questions concerning the filing could be handled informally through either telephone conversations or an informal technical conference during the 30-day period.

- For the filing of the AAF, the 45-day review period, would allow time for a more extensive review. During this period, the Commission could make inquiries with

Delta by either contacting them by telephone or submitting written inquiries. The Commission could also conduct an informal technical conference to go over the information submitted by Delta in the filing and in response to inquiries. An alternative to this would be to conduct an expedited evidentiary hearing during the 45-day review period. However, we feel that a more effective process would consist of using informal oral and written communications and informal technical conferences if necessary to answer questions raised by the Commission.

- For the filing of the BAF, the 30-day period should allow sufficient time for the Commission to review the reconciliation of the AAF and prior BAFs based on differences between projected and actual billing units used in the application of these components. Although it is unlikely that any substantive issues will arise during the review of the BAF, any inquires could be handled informally.

WITNESS: Steve Seelye

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

| | | |
|---|---|---|
| An Adjustment of Rates of | ) | Case No. 99-176 |
| Delta Natural Gas Company, Inc. | ) | |

ATTORNEY GENERAL

CROSS EXHIBIT 9

A G. Cross
EXHIBIT NO. 9
V. LEWIS

Delta Natural Gas Company, Inc.
Case No. 99-176

AG DATA REQUEST
Dated 9/4/99

28. The response to AG-66 indicates that the actual collection revenues for the first 7 months of 1999 averaged $10,105 per month as opposed to the average collection revenues of $6,500 per month in the 1998 test year. Please provide the reasons for the significant increase in these average monthly collection revenues. In addition, provide the actual collection revenues for the month of August 1999.

RESPONSE:

The Company made a conscious effort during the 1999 fiscal year to more aggressively enforce the Company's collection policies. This action reduced bad debt expense for the year and increased collection revenue. Collection revenue for August 1999 was $3,870.

WITNESS: John Brown

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

| | | |
|---|---|---|
| An Adjustment of Rates of<br>Delta Natural Gas Company, Inc. | )<br>) | Case No. 99-176 |

ATTORNEY GENERAL

CROSS EXHIBIT 10

A.G. Cross
EXHIBIT NO. 10
V. LEWIS

# GAS DISTRIBUTION RATE DESIGN MANUAL

Prepared by
NARUC Staff Subcommittee on Gas

June 1989

Published by

NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS
1102 Interstate Commerce Commission Building
Constitution Avenue and Twelfth Street, NW
Post Office Box 684
Washington, DC 20044-0684
Telephone No. (202) 898-2200

Price: $17.00

accordance with prescribed uniform accounting systems. These systems, such as the Uniform System of Accounts, classify costs according to primary operating functions. Thus, the functionalization of costs is already done for the cost of service analyst.

2. Classification of Costs

The functionalization of costs is of limited use in the allocation of costs. Therefore, it is necessary to further classify costs into customer, energy or commodity, and demand or capacity costs.

a. Customer Costs

Customer costs are those operating capital costs found to vary directly with the number of customers served rather than with the amount of utility service supplied. They include the expenses of metering, reading, billing, collecting, and accounting, as well as those costs associated with the capital investment in metering equipment and in customers' service connections.

A portion of the costs associated with the distribution system may be included as customer costs. However, the inclusion of such costs can be controversial. One argument for inclusion of distribution related items in the customer cost classification is the "zero or minimum size main theory." This theory assumes that there is a zero or minimum size main necessary to connect the customer to the system and thus affords the customer an opportunity to take service if he so desires.

Under the minimum size main theory, all distribution mains are priced out at the historic unit cost of the smallest main installed in the system, and assigned as customer costs. The remaining book cost of distribution mains is assigned to demand. The zero-inch main method would allocate the cost of a

There may be difficulty in getting customers to accept test meters, since their premises must be available for meter printout sheet or tape replacement where necessary so that the test data will be continuous for the period involved. This complicates the selection procedure.

The selection process must result in a valid statistical sample. Ultimately, there must be selected a representative cross-section of customers willing to cooperate in the test-metering program, sufficiently large in number to be statistically significant. About three times the number of customers for which tests are needed must be initially selected. Factors such as examination of the types of customers produced by the random selection to assure that they are representative; field inspection of premises to determine type of premises; connected load and number of people who live or work on the premises; and unwillingness or inability of a customer to cooperate, all must eventually be tested. A considerable expenditure of time and manpower is needed to complete the process.

## C. Illustrative Embedded Cost of Service Study

A cost of service study is a series of choices regarding potentially controversial methods of identifying and allocating costs incurred by a utility. This illustrative study represents one possible means of computing class cost of service. There are many other equally correct methods. For illustrative purposes, the following example demonstrates how the factors discussed above are utilized in a fully allocated cost of service study.

The first step in preparation of the study is a separation of all plant and expense items incurred during the test period into the functional categories of production, storage, transmission, distribution and general. This functionalization is shown throughout the study on Schedules 3, 4 and 5, according to Monopolytown's accounting system. Where possible, functional costs are directly assigned to the classes of service based upon details from the utility's books or by special analysis or studies. This is illustrated in Schedule No. 2 where Rate Revenues are directly assigned to the classes which produce them.

The costs not directly assignable were allocated among the customer classifications according to factors developed from the basic statistical data. The derivation of the allocation factors is illustrated on Schedules 10 and 11. The following is an explanation of the major allocation factors used in this study.

The Peak Day Demand (Allocation Factor 100) is the computed quantity of gas which would be supplied on a day when the mean temperature of the utility's service territory is 5 degrees Fahrenheit (the coldest day in 20 years for this particular system), which equates to a 60 degree-day deficiency. Schedule No. 12 provides the details of the peak day calculations. There are two predominant Commodity allocation factors which consist of normalized and curtailed gas sales during the test period. Factor No. 110 is comprised of sales without transportation volumes. Factor No. 120 is the total throughput quantity which includes gas sales and transportation. The primary Customer allocation factor, No. 160, consists of the number of bills rendered during the test period.

Once the allocation factors are prepared, they should be applied to the functionalized costs in relation to how those costs are incurred by the utility. Expenses and plant are classified or considered to be fixed, variable, customer, or revenue related. Classification is an integral part of the allocation process and once costs are classified, the appropriate allocation factors are applied to these costs as shown in the last column in each of Schedules 2 through 9. Fixed costs are normally allocated on the basis of demand, while variable costs are allocated on the basis of commodity sales. Costs incurred as a result of a customers' connection to the utility system are allocated on the basis of a customer factor, and costs related to revenues are allocated on the basis of a revenue factor. Costs which cannot be related to one of the four basic classifications are allocated on the basis of a composite factor, reflecting two or more elements of the expense or plant accounts. This is illustrated on Schedule No. 4 where account 374 (land and land rights) is allocated on the basis of allocation Factor No. 13, which reflects a composite of the allocation of all other distribution plant.

As a more detailed explanation of the allocation process, consider the allocation of utility plant which is shown on Schedule No. 4. Production plant, which includes a propane-air facility, was designed and constructed by the utility to meet peak load requirements. Consequently, production plant has been allocated on the basis of peak day demand (Allocation Factor No. 100).

The distribution plant investment in mains may be classified as both demand and customer related. The customer component was determine as the amount of investment that would be required it all mains were comprised of a theoretical minimum size. Monopolytown's smallest mains (1.5 inch diameter) were installed at an average unit cost of $0.61 per foot. The customer component of mains is computed by multiplying the total length of mains (6,385,860 feet) by the unit cost of the smallest mains. The resulting amount ($3,988,733) represents approximately 20 percent of the total investment in mains. The remaining 80 percent is considered to be demand related. Therefore, the investment and expenses associated with mains are allocated on the basis of composite allocation Factor No. 150. Factor No. 150 is a weighted average of allocation Factor No. 160 (20 percent weight) and Factor No. 100 (80 percent weight).

d. Other Costs

Other costs, such as those associated with common plant, working capital and administrative and general expenses, cannot be readily categorized as either customer, energy or demand. Thus, they are not normally allocated on the basis of a single classification. These other costs are generally allocated on a composite basis of certain other cost categories. For example: common plant may be allocated on the composite allocation of all production, transmission, storage and distribution plant; and administrative and general expenses may be allocated in accordance with the composite allocation of all other operating and maintenance expense, excluding the cost of gas.

4. Methods of Allocation of Demand or Capacity Costs

a. Theory

There is a wide variety of alternative formulas for allocating and determining demand costs, each of which has received support from some rate experts. No method is universally accepted, although some definitely have more merit than others. The electric industry has produced more alternatives than the gas industry. For instance, in an early 1950 case before the Illinois Commerce Commission, an executive of Commonwealth Edison Company noted the existence of 29 different formulas for the apportionment of demand costs. The application of these formulas produced drastically different cost assignments to the several service classifications. As a result, the Illinois Commission refused to direct that the utility present such evidence. The NARUC published in 1955, through its Engineering Committee, a detailed discussion of 16 such methods.

The multiplicity of available methods (which in fact reflects the insoluble nature of the problem) has led many recognized experts to express grave doubts about the efficacy of cost of service analyses.

The most commonly used demand allocations for natural gas distribution utilities are the coincident demand method, the non-coincident demand method, the average and peak method, or some modification or combination of the three.

b. <u>Coincident Demand Method</u>

In the coincident demand (peak responsibility) method, allocation is based on the demands of the various classes of customers at the time of system peak. This method favors high load factor customers who take gas at a steady rate all year long by assigning the greater percentage of demand costs to lower load factor heating customers whose consumption is greatest at the time of the system peak. Generally, interruptible customers would receive no allocation of demand costs under this formula since they should be off the system during the peak period. The demand component of the cost of gas is generally allocated on a coincident demand method.

c. <u>Noncoincident Demand Method</u>

This method would result in all classes of customers being allocated a portion of system cost based upon their actual peak, regardless of the time of its occurrence. This method assigns cost to customer classes such as interruptibles, and thereby reduces the costs allocated to the heating customer under the peak demand method. The demand related portion of distribution mains and transmission mains are commonly allocated on a noncoincident demand method.

d. <u>Average and Peak Demand Method</u>

This method reflects a compromise between the coincident and noncoincident demand methods. Total demand costs are multiplied by the system's load factor to arrive at the capacity costs attributed to average use and are apportioned to the various customer classes on an annual volumetric basis. The remaining costs are considered to have been incurred to meet the individual peak demands of the

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

| | | |
|---|---|---|
| An Adjustment of Rates of | ) | Case No. 99-176 |
| Delta Natural Gas Company, Inc. | ) | |

ATTORNEY GENERAL

CROSS EXHIBIT 11

A.G. Cross
EXHIBIT NO. 11
V. LEWIS

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
1046
JUN 02 1987
Division of Consumer Protection
Utility Section
Frankfort, Kentucky

In the Matter of:

| | | |
|---|---|---|
| AN INVESTIGATION OF THE IMPACT OF | ) | |
| FEDERAL POLICY ON NATURAL GAS | ) | ADMINISTRATIVE |
| TO KENTUCKY CONSUMERS AND SUPPLIERS | ) | CASE NO. 297 |

I N D E X

in marginal transportation rates currently in effect to meet competition from alternate energy.[89]

The Commission has again reviewed the record concerning submission of cost-of-service studies and finds they should be submitted in the next rate case of each Class A LDC. As cost-of-service studies are used in determining cost allocations across all customer classes, they cannot be separated from a rate case. The decision to file a rate case is appropriately left to each utility. However, when the Commission has an issue that requires a company response it uses an investigative procedure. In the event a significant interval of time should pass before a Class A LDC files a rate case with a cost-of-service study, the Commission may require a response from that LDC. Regarding Southern's concern about flexibility, the Commission will continue to allow a flexible rate provision. Finally, the Commission confirms LG&E's commentary that conforming tariff changes, not involving rates, will be considered outside a rate case.

Selection of Cost-of-Service Methodology

In answer to the Commission's January 17, 1987, request for testimony, Delta stated, "We do not feel that a generic approach to cost-of-service studies is appropriate."[90] LG&E[91] and WKG[92] agreed with Delta.

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89 Southern response to Commission's Order dated September 30, 1986, page 10.

90 T.E., page 38.

91 T.E., page 85.

92 T.E., page 110.

GTE said the Commission had not had the time or received adequate testimony about the merits or deficiencies of available cost-of-service methodologies to select one or two and impose them on all LDCs.[93] GTE suggested that the Commission consider the question of an appropriate methodology on a case-by-case basis.[94]

In the opinion of Southwire, the Commission could avoid delay by setting a timetable for the filing of a rate case based on cost of service and for a generic consideration of appropriate cost-of-service methodologies.[95] The AG stated, "The Commission should consider cost allocation studies after it has established a fair and uniform methodology or set up a range for the studies as suggested by the AG, but it should not slavishly follow them or suggest that somehow they yield a 'correct answer.'"[96]

WKG encouraged the Commission to set up a conference with each utility to discuss how the cost-of-service study should be filed and what methods should be used.[97]

The record indicates that the parties have different opinions concerning the selection of a cost-of-service methodology. The LDCs and GTE generally prefer a case-by-case decision on cost allocation methodologies. Southwire and the AG recommend a

---

93 T.E., page 178.

94 Ibid.

95 Southwire response to Commission's Order dated September 30, 1986, page 6.

96 AG response to Commission's Order dated September 30, 1986, pages 13 and 14.

97 T.E., page 105.

generic approach. KIUC believes the coincident demand or peak responsibility method explained in Gas Rate Fundamentals is most appropriate.[98]

The Commission finds that there are significant differences among Class A LDCs that merit case-by-case decisions on cost-of-service methodologies. The Commission is of the opinion that each Class A LDC should schedule an informal conference early in the development of its cost-of-service study. The Commission staff, as well as intervenors from the company's last rate case, should be invited to participate.

As several commenters stated, there are a variety of techniques available for cost-of-service studies. The Commission acknowledges that there is not a single acceptable method to prepare such a study. Each LDC is encouraged to choose the method it finds appropriate.

The Commission is concerned about cost-of-service methodologies that place all the emphasis on maximum design day as a way to allocate costs. This method may result in an inappropriate shift of costs to the residential customer class. For this reason, cost-of-service methodologies should give some consideration to volume of use.

## TRANSPORTATION

### Burden of Proof

In accord with KRS 278.490 and KRS 278.505, transportation should be contingent only on the availability of adequate capacity

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98 T.E., page 197.

HISTORY INDEX FOR CASE: 1999-176
DELTA NATURAL GAS COMPANY, INC.
Rates - General
HISTORICAL TEST PERIOD

IN THE MATTER OF AN ADJUSTMENT OF RATES OF DELTA NATURAL GAS COMPANY, INC.

| SEQ NBR | ENTRY DATE | REMARKS |
|---|---|---|
| 0001 | 04/29/1999 | Notice of Intent. |
| 0002 | 04/30/1999 | Acknowledgement letter of Notice of Intent. |
| 0003 | 07/02/1999 | Application. |
| M0001 | 07/02/1999 | ORDA LEDFORD CITIZEN-LETTER OF CONCERN TO INCREASE |
| 0004 | 07/06/1999 | Acknowledgement letter. |
| M0002 | 07/07/1999 | DELTA NATURAL GAS-MOTION TO CONSOLIDATE & MAINTAIN PROCEDURAL SCHEDULE |
| 0006 | 07/08/1999 | Response sent to Odra Ledford protest letter. |
| 0005 | 07/09/1999 | No deficiency letter. |
| M0003 | 07/09/1999 | E BLACKFORD AG-MOTION TO INTERVENE |
| 0007 | 07/13/1999 | Order granting motion of the Attorney General for full intervention. |
| M0005 | 07/13/1999 | ROBERT WATT DELTA NATURAL GAS-REPLY IN SUPPORT OF MOTION TO CONSOLIDATE & MAINTAIN PROCEDUR |
| 0008 | 07/15/1999 | Data Request Order; response due 7/29 |
| M0006 | 07/26/1999 | CRACRAFT,RITCHIE CITIZENS-LETTER OF CONCERN TO RATE INCREASE |
| 0009 | 07/28/1999 | Response sent to Frank and Dolly Cracraft letter of concern to rates. |
| 0010 | 07/28/1999 | Response sent to C.B. Ritchie letter of concern to rates. |
| M0007 | 07/28/1999 | ROBERT WATT DELTA NATURAL GAS-RESPONSE TO PSC DATA REQ FOR INFO DATED JULY 15,99 |
| 0011 | 07/30/1999 | Order setting forth the procedural schedule to be followed in this case. |
| 0012 | 08/05/1999 | Order denying motion to consolidate; Case No. 99-046 is dismissed. |
| 0013 | 08/11/1999 | Data Request Order, response due 8/23/99. |
| M0008 | 08/11/1999 | BERNICE CHEEKS CITIZEN-LETTER OF CONCERN TO RATES |
| M0009 | 08/11/1999 | AG E BLACKFORD-INITIAL REQUEST FOR INFORMATION BY THE AG |
| M0010 | 08/13/1999 | E BLACK FORD AG-NOTICE OF CORRCTIN IN THE INITIAL REQ FOR INFO BY THE AG |
| M0011 | 08/18/1999 | ROBERT WATT DELTA NATURAL GAS-NOTICE OF FILING PROOF OF PUBLICATION |
| M0012 | 08/23/1999 | ROBERT WATT DELTA NATURAL GAS CO-RESPONSE TO DATA REQUEST OF THE PSC & AG DATED AUG 11,99 |
| 0014 | 08/30/1999 | Interest & Concern resp. to Bernice Cheeks; req. to intervene may be filed. |
| 0016 | 09/01/1999 | Letter advising that a disk is missing from Delta's response filed on 8/23/99. |
| 0015 | 09/02/1999 | Data Request Order, response due 9/13/99. |
| M0013 | 09/02/1999 | RANDALL WALKER DELTA NATURAL GAS-DISKETTE TO QUESTION 6 TO RESPONSE TO ORDER OF AUGUST 11,9 |
| M0014 | 09/03/1999 | E BLACKFORD AG-SUPPLEMENTAL REQUEST FOR INFORMATION |
| M0015 | 09/07/1999 | JOHN HALL DELTA NATURAL GAS-MONTHLY UPDATE TO QUESTION NO 48 |
| M0016 | 09/13/1999 | ROBERT WATT DELTA NATURAL GAS-RESPONSE TO SUPPLEMENTAL DATA REQ OF THE PSC & AG DATED SEPT |
| 0017 | 09/14/1999 | Data Request Order, response due 9/24/99. |
| M0019 | 09/23/1999 | E BLACKFORD AG-PREFILED TESTIMONY HENKES,GALLIGAN,ESTOMIN,WEAVER |
| M0017 | 09/24/1999 | J. MEL CAMENISCH DELTA NATURAL GAS-RESPONSE TO DATA REQUESTS DATED 9/14/99 & MOTION OF CONF |
| M0018 | 09/28/1999 | E BLACKFORD AG-CERTIFICATE OF SERVICE & OF FILING |
| 0018 | 10/04/1999 | Data Request Order, response due 10/14/99 from the Attorney General. |
| M0020 | 10/04/1999 | ROBERT WATT DELTA NATURAL GAS-DATA REQ TO AG |
| M0021 | 10/06/1999 | JOHN HALL DELTA NATURAL GAS CO-MONTHLY UPDATE TO QUESTION NO 48 OF DATA REQ FILED JULY 15,9 |
| M0022 | 10/14/1999 | AG E BLACKFORD-AG RESPONSES TO DATA REQ PROPOUNDED BY DELTA NATURAL GAS CO |
| M0023 | 10/14/1999 | E BLACKFORD AG-MOTION FOR ENLARGEMENT OF TIME |
| M0024 | 10/14/1999 | AG E BLACKFORD-AG RESPONSE TO PSC ORDER OF OCT 4,99 |
| 0019 | 10/18/1999 | Letter granting petition for confidentiality filed 9/24/99 by Delta. |
| M0026 | 10/25/1999 | ROBERT WATT DELTA NATURAL GAS-TESTIMONY OF SEELYE,BLAKE,BROWN |
| M0025 | 10/27/1999 | E BLACKFORD AG-NOTICE THAT ATTACHMENTS RESPONSIVE TO DATA REQ 26 ARE NOT INCLUDED AS |
| 0020 | 10/28/1999 | Order granting the AG an additional day to respond to Delta's info requests. |
| M0027 | 10/28/1999 | DELTA NATURAL GASROBERT WATT-MOTION TO STRIKE TESTIMONY OF AG WITNESSES |
| M0028 | 10/28/1999 | AG E BLACKFORD-MOTION TO STRIKE & BAR FROM CONSIDERATION CERTAIN TESTIMONY |
| M0029 | 10/29/1999 | AG E BLACKFORD-RESPONSE TO DELTA MOTION TO STRIKE TESTIMONY OF AG WITNESSES |
| M0030 | 10/29/1999 | DELTA ROBERT WATT-RESPONSE TO AG MOTION TO STRIKE |

DELTA NATURAL GAS COMPANY, INC.
Rates - General
HISTORICAL TEST PERIOD

IN THE MATTER OF AN ADJUSTMENT OF RATES OF DELTA NATURAL
GAS COMPANY, INC.

| SEQ NBR | ENTRY DATE | REMARKS |
|---|---|---|
| 0021 | 11/03/1999 | Letter containing PSC Staff questions; answers due no later than 11/17/99. |
| M0031 | 11/04/1999 | E BLACKFOR AG-NOTICE OF FILING & CERTIFICATE OF SERVICE |
| M0032 | 11/09/1999 | VIVIAN LEWIS/COURT REPORTER-HEARING EXHIBITS HELD 10/28/99 |
| M0033 | 11/09/1999 | VIVIAN LEWIS/COURT REPORTER-TRANSCRIPT FOR HEARING HELD 10/28/99 VOL. I OF II |
| M0034 | 11/12/1999 | JOHN HALL DELTA NATURAL GAS-RESPONSE TO STAFF REQUEST MADE DURING HEARING HELD ON OCT 28,29 |
| M0035 | 11/12/1999 | VIVIAN LEWIS/COURT REPORTER-TRANSCRIPT FOR HEARING HELD 10/29/99 |
| M0036 | 11/17/1999 | E BLACKFORD AG-RESPONSE TO POSTHEARING DATA REQ BY KY PSC ON NOV 3,99 |
| M0037 | 11/17/1999 | JOHN HALL DELTA NATURAL GAS-RESPONSE TO POST HEARING STAFF REQ MADE TO STEVE SEELYE |
| M0038 | 11/29/1999 | ROBERT WATT DELTA NATURAL GAS-BRIEF |
| M0039 | 11/29/1999 | AG-POSTHEARING BRIEF |
| 0022 | 11/30/1999 | Order denying Delta's Motion to Strike the Testimony of the AG's Witnesses. |
| 0023 | 12/27/1999 | Final Order approving rates in Appendix B and approving proposed WNA. |
| M0040 | 01/06/2000 | CONNIE KING DELTA NATURAL GAS-REVISED TARIFF SHEETS |
| M0041 | 01/10/2000 | CONNIE KING DELTRAN INC-RESPONSE TO ORDER OF DEC 27,99 |
| M0042 | 01/18/2000 | AG E BLACKFORD-MOTION FOR REHEARING |
| M0043 | 02/01/2000 | ROBERT WATT DELTA NATURAL GAS-RESPONSE TO AG MOTION FOR REHEARING |
| 0024 | 02/07/2000 | Order on Rehearing |

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
211 SOWER BOULEVARD
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

# CERTIFICATE OF SERVICE

RE: Case No. 1999-176
DELTA NATURAL GAS COMPANY, INC.

I, Stephanie Bell, Secretary of the Public Service Commission, hereby certify that the enclosed attested copy of the Commission's Order in the above case was served upon the following by U.S. Mail on February 7, 2000.

Parties of Record:

John F. Hall
Vice President-Finance, Sec.,Treas.
Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY. 40391

Honorable Robert M. Watt,
Counsel for Delta Natural Gas
Stoll, Keenon & Park, LLP
201 East Main Street
Suite 1000
Lexington, KY. 40507 1380

Honorable Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY. 40601

Stephanie J. Bell
Secretary of the Commission

SB/hv
Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

| | |
|---|---|
| AN ADJUSTMENT OF THE RATES OF DELTA NATURAL GAS COMPANY, INC. | ) CASE NO. 99-176 ) |

ORDER

On December 27, 1999, the Commission issued an Order in this proceeding in which, inter alia, we authorized rates that will produce additional operating revenues of $419,702 annually. Alleging certain errors that require the reduction of this rate adjustment, the Attorney General ("AG") has moved for rehearing of that Order. Having reviewed the AG's motion and the response of Delta Natural Gas Company, Inc. ("Delta"), we grant the motion in part and deny in part.

In his motion, the AG contends that the Commission erred in our decision in three respects. First, he contends that the Commission committed a mathematical error when calculating Delta's revenue requirement. He asserts that when the gross-up factor of 1.66532608 is multiplied by the Revenue Deficiency of $1,766,106, the correct product is $2,941,142 rather than the $2,957,796 Revenue Requirement increase reported in the Order.[1]

Based upon our review of the Order of December 27, 1999, we find that a typographical error occurred. The Order should have noted a "Revenue Deficiency" of $1,776,106 instead of a "Revenue Deficiency" of $1,766,106 as stated. When the

[1] See Order of December 27, 1999 at 34.

correct "Revenue Deficiency" is used, a revenue requirement increase of $2,957,796 results.[2] While this typographical error does not affect the amount of the revenue requirement found reasonable, the Commission finds that the Order of December 27, 1999 should be amended to correct this error.

The AG next contends that the Commission erred in failing to exclude property insurance expense when adjusting expenses to reflect year-end customers. He contends that this expense does not vary with incremental customer sales and should not, therefore, be adjusted to reflect customer growth. The AG advanced this argument at hearing and in his written brief. We carefully considered his argument in rendering our decision and rejected it.[3] As the AG merely reargues this point in his motion and has not presented any new evidence or argument on this point, we find no basis for rehearing and deny his motion on this issue.

Finally, the AG argues that we erred in our treatment of Delta's rate case and management audit expenses. He asserts that Delta's management audit expense will be fully amortized in November 2000. Unless Delta's rates are adjusted in a general rate proceeding prior to December 1, 2000, he further asserts, Delta will over recover its management audit amortization expense at an annual rate of $62,400 beginning in

---

[2]

| | |
|---|---|
| Net Investment Rate Base | $ 91,997,648 |
| Rate of Return | x 8.5556% |
| Required Operating Income | $ 7,870,951 |
| Adjusted Operating Income | - 6,094,845 |
| Revenue Deficiency | $ 1,776,106 |
| Gross-up Factor | x1.66532608 |
| Required Increase, Inclusive of Income Taxes, PSC Assessment and Uncollectibles | $ 2,957,796 |

[3] Order of December 27, 1999 at 13 – 14.

December 2000. Consistency with the Commission's treatment of the rate case expenses arising from Case No. 97-066,[4] therefore requires that the Commission re-amortize the unamortized management audit balance of $57,420[5] over a three-year period. The AG's proposal would result in a pro forma expense reduction of $43,500.[6]

This argument merely rehashes the arguments that the AG presented at hearing[7] and that we considered in reaching our decision.[8] As the AG has presented no new evidence or argument to disturb our original findings, we find no basis upon which to grant the AG's motion.

IT IS THEREFORE ORDERED that:

1. The AG's Motion for Rehearing is granted in part and denied in part.

2. Page 34, line 13 of the Commission's Order of December 27, 1999 is amended to read as follows:

"Revenue Deficiency $1,776,106"

3. The Commission's Order of December 27, 1999 is affirmed in all other respects.

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[4] Case No. 97-066, An Adjustment of General Rates of Delta Natural Gas Company, Inc. (Dec. 8, 1997).

[5] As of January 12, 1999, unamortized management audit expense was $57,420.

[6] AG's Motion for Rehearing at 2 - 3.

[7] Transcript, Vol. II, at 141 and 142.

[8] Order of December 27, 1999 at 18 – 21.

Done at Frankfort, Kentucky, this 7th day of February, 2000.

By the Commission

ATTEST:

Executive Director

# Deltran, Inc.

A Subsidiary Of Delta Natural Gas Co., Inc.
3617 Lexington Road
Winchester, Kentucky 40391

January 7, 2000

RECEIVED
JAN 1 0 2000
PUBLIC SERVICE
COMMISSION

Ms. Helen C. Helton
Executive Director
Public Service Commission
P O Box 615
Frankfort, KY 40602

Dear Ms. Helton:

Pursuant to the Commission's Order dated December 27, 1999 in Case No. 99-176, which was effective January 1, 2000, the Canada Mountain gas storage facilities of Delta Natural Gas Company, Inc. ("Delta") were included in the calculation of Delta's base rates and removed from Delta's Gas Cost Recovery Clause calculations. Delta has filed tariffs reflecting the Commission's order. As a result of this change, Delta and Deltran, Inc. ("Deltran"), Delta's subsidiary, have, effective January 1, 2000, terminated their Gas Storage Agreement dated January 1, 1996, and their Lease Agreement dated January 1, 1996, both of which related to the Canada Mountain field and are now unnecessary given the Commission's decision in this recent order.

Deltran has on file with the Commission its Rates, Rules and Regulations for furnishing Underground Natural Gas Storage Service. Deltran's only customer was Delta. Deltran hereby withdraws said Rates, Rules and Regulations of Deltran, which were issued November 30, 1995, and we request that the Commission appropriately remove and cancel them. This includes Deltran's tariff sheets Original No. 1 through 6, which comprise all of Deltran's tariffs.

Delta intends to proceed with the dissolution of Deltran as it is now inactive.

Sincerely,

Connie King

Connie King
Director – Rates & Treasury

# STOLL, KEENON & PARK, LLP



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February 1, 2000

Hon. Martin J. Huelsmann
Executive Director
Public Service Commission
730 Schenkel Lane
P.O. Box 615
Frankfort, KY 40602



Re: Delta Natural Gas Company, Inc.
Case No. 99-176

Dear Mr. Huelsmann:

We deliver herewith for filing an original and ten (10) copies of Delta's Response to the Attorney General's Motion for Rehearing in the above-captioned case. We would appreciate your placing the Response with the other papers in the case and bringing it to the attention of the Commissioners. Thank you for your kind assistance.

Sincerely,

Robert M. Watt

Robert M. Watt, III

rmw
encl.
cc: Counsel of Record (w/encl.)
Mr. John F. Hall (w/ encl.)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
FEB 01 2000
PUBLIC SERVICE COMMISSION

**In the Matter Of:**

| | | |
|---|---|---|
| **AN ADJUSTMENT OF RATES OF** | ) | |
| **DELTA NATURAL GAS COMPANY, INC.** | ) | **CASE NO. 99-176** |

* * * * * * * * * * *

## RESPONSE OF DELTA NATURAL GAS COMPANY, INC. TO ATTORNEY GENERAL'S MOTION FOR REHEARING

Delta Natural Gas Company, Inc. ("Delta") respectfully submits this response to the Attorney General's Motion for Rehearing served on January 17, 2000, (and received by counsel for Delta on January 21, 2000) herein. The Motion for Rehearing is largely a rehash of matters argued to and decided by the Commission and should be denied.

The first item in the Motion for Rehearing is an alleged error in the product of the Gross-up Factor and the Revenue Deficiency on page 34 of the Order herein. Delta agrees that the arithmetic on page 34 of the Order should result in the sum of $2,941,142 if one assumes that the Gross-up Factor is correctly set forth. Delta did not utilize the Gross-up Factor approach that is set forth in the Order and cannot determine if the Gross-up Factor is correctly stated in the Order. If not, then the multiplier and not the product is in error. Moreover, Delta has already implemented the rates approved in the Order and the expense and customer confusion resulting from making the change the Attorney General proposes exceed the benefit the customers would receive.

The second item is the reargument of the proposal that property insurance be excluded from the expense ratio utilized in the revenue adjustment. The issue has been proposed and rejected by the Commission and the Attorney General offers no new evidence compelling the Commission to reverse its decision. On page 28 of the direct testimony of the Attorney General's witness, Mr. Henkes, the following testimony appears: "I also do not believe that regulatory, property insurance, outside services and miscellaneous general expense vary with the incremental sales recognized in the case as a result of the year end sales annualization adjustment." This is the extent of Mr. Henkes' testimony on the subject. There was no supporting analysis of this matter. The Commission considered the evidence offered and rejected Mr. Henkes' contention regarding property insurance.[1] See Order at 13-14 There was good reason for the rejection. Plant levels, and the related property insurance expense, clearly increase with growth in customers. It is impossible to add customers without adding plant. Property insurance expense is based on the value of the property, in this case, utility plant. Thus, if customer growth occurs, then property insurance expense will increase.

The third item in the Attorney General's Motion for Rehearing is a reargument of the treatment of the management audit expense. The Attorney General admits that he is rearguing an issue that Mr. Henkes addressed at the hearing (see page 3 of the Motion for Rehearing), but persists in presenting it again. The treatment of management audit expense is consistent with its treatment in Case No. 97-066 and consistent with the Commission's intentions when management audits were required of utilities. The Attorney General opposes the **Commission's** amortization of management audit expense, even though his witness, Mr. Henkes, argued in favor of amortization of management audit expense at the hearing. Transcript, Volume 2 at 140. Instead, he proposes amortization of the

[1]The Commission rejected Delta's proposal to include the full level of the salary of Delta's president in the face of much more compelling evidence than Mr. Henkes offered on the exclusion of property insurance expense from the expense ratio. See pages 16-17 of the Order.

amortized management audit expenses. This approach is inconsistent with the Commission's customary amortization methodology. The Attorney General, through Mr. Henkes, has previously presented the management audit expense argument contained in the Motion for Rehearing and the Commission has rejected it. It should not be accepted by way of Motion for Rehearing.

For the foregoing reasons, Delta respectfully submits that the Attorney General's Motion for Rehearing should be denied.

Respectfully submitted,

STOLL, KEENON & PARK, LLP

By Robert W Watt

Robert M. Watt, III
201 East Main Street, Suite 1000
Lexington, KY 40507
606-231-3000

Counsel for Delta Natural Gas Company, Inc.

## CERTIFICATE OF SERVICE

This is to certify that the foregoing pleading has been served by mailing a copy of same, postage prepaid, to the following person on this 2d day of February 2000.

Elizabeth E. Blackford, Esq.
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY 40601-8204

Robert W Watt

Robert M. Watt, III

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

RECEIVED
JAN 1 8 2000
PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| An Adjustment of Rates of<br>Delta Natural Gas Company, Inc. | )<br>) | Case No. 99-176 |

## MOTION FOR REHEARING

Comes the Attorney General pursuant to KRS 278.400 and moves the Commission to rehear three matters arising from its Order of December 27, 1999.

1. An error in the math pertaining to the revenue requirement occurred on page 34 of the Order. There the Gross-up Factor of 1.66532608 was multiplied by the Revenue Deficiency number of $1,766,106 to produce a Revenue Requirement increase of $2,957,796. This is an error. The correct product of that equation is $2,941,142. The Order should be amended or clarified to reflect a Revenue Requirement increase of $2,941,142.

2. The Commission has found that wages and salaries, pensions and benefits and regulatory commission expenses do not change in the short-term with the growth in year-end customers, and therefore, has applied an expense ratio of 10.63% to the revenue adjustment amount of $423,668. Order, pages 12-13. The Attorney General urged the Commission to further exclude outside services employed, miscellaneous general expenses and property insurance. (See, Schedule RJH-8).

Consistency demands that the Commission exclude at least property insurance. Property insurance is primarily a function of plant level which does not change in the short-term with the growth of year-end customers. As the expense does not vary with incremental customer sales, it too should be excluded from the adjustment for expanses associated with year-end customer growth. Excluding property insurance would result in a 8.38% expense to revenue ratio and an associated expense of $35,503 (8.38% x $423,668 = $35,503).

3. The Commission has carried forward two expenses which were amortized in Case No. 97-066: the rate case expenses, which were amortized over five years, and the management audit expenses, which were amortized over three years. Both expenses were approved for collection in this case to prevent Delta from failing to recover previously recognized and approved expenses.

The total costs of the management audit was approximately $187,700 which was amortized in Case No. 97-066 over three years at $62,640 per annum. (See, Delta's response to the Supplemental Data Requests of the Attorney General, Number 25). As shown on page 233 of Delta's 1998 FERC Form 2, the unamortized balance as of December 31, 1998, was $120, 060. Another $62,640 of amortized expense was booked and collected in rates in 1999, leaving an unamortized expense balance of $57, 420 as of December 31, 1999.

On the current amortization schedule, the unamortized balance of $57,420 will be fully amortized and collected in rates around the end of November, 2000. Delta would have to have another rate case with rates effective December 1, 2000, which recognize the expiration of the unamortized management audit expense balance to avoid over recovery of the expense at the current rate of amortization. It is not reasonable to assume that this will occur. If the rates established in the instant proceeding do not change prior to December 1, 12000, Delta will over recover its management audit amortization expense at an annual rate of $62,400 starting December 1, 2000.

It is no more fair to build in a guaranteed over recovery of a recognized expense than it is to prevent recovery of a recognized expense. The Commission has accepted Delta's recommendation that rate case expenses from this current case be amortized over three years, with its correlative assumption that it will be three years before Delta comes back in for another rate case.[1] In order to prevent over recovery of the management audit amortized expenses, the uncollected balance of that expense should be re-amortized over a three year period to match the amortization of the rate case expenses. This will allow recovery of the recognized expense, but prevent its over recovery by utilizing the reasonable assumption Delta has put forth as to the duration of the interval between rate cases.

To be consistent with the approach taken by the Commission with reference to the rate case expenses arising from Case No. 97-066, the Commission should re-amortize the management audit balance of $57,420 existing as of January 12, 1999 over three years, a period which tracks the amortization period proposed and adopted for the rate case expenses of the current case. This would result in an annual amortization expense level of $19,140 per annum. It would also result in a pro forma expense reduction in this case of $43,500 ($62,640 - $19,140 = $43,500). This suggestion was made by Mr. Henkes at the hearing. (Transcript of Evidence, Vol. II of II, pp. 141-142). This treatment will prevent over recovery of the amortized management audit expenses arising from the prior case, just as the continued recognition and collection of the rate case expense prevents the under recovery of that expense.

Respectfully Submitted,

EE Blackford

Elizabeth E. Blackford

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[1] It has also adopted a weather normalization clause which reduces the likelihood that Delta will need to return for another rate case before three years.

CERTIFICATE OF SERVICE AND NOTICE OF FILING

I hereby give notice that this the 17th day of January, 2000, I have filed the original and eight true copies of the foregoing with the Public Service Commission at 730 Schenkel Lane, Frankfort, Kentucky, 40601, and certify that I have served the parties by mailing true copies of same, postage prepaid this same date to the following:

JOHN F HALL
VICE PRESIDENT-FINANCE SEC TREAS
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER KY 40391

HONORABLE ROBERT M WATT III
STOLL KEENON & PARK LLP
201 EAST MAIN STREET SUITE 1000
LEXINGTON KY 40507 1380

/s/ Blackford

COMMONWEALTH OF KENTUCKY
**PUBLIC SERVICE COMMISSION**
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

# CERTIFICATE OF SERVICE

RE: Case No. 1999-176
DELTA NATURAL GAS COMPANY, INC.

I, Stephanie Bell, Secretary of the Public Service Commission, hereby certify that the enclosed attested copy of the Commission's Order in the above case was served upon the following by U.S. Mail on December 27, 1999.

Parties of Record:

John F. Hall
Vice President-Finance, Sec.,Treas.
Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY. 40391

Honorable Robert M. Watt
Counsel for Delta Natural Gas
Stoll, Keenon & Park, LLP
201 East Main Street
Suite 1000
Lexington, KY. 40507 1380

Honorable Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY. 40601

Stephanie J. Bell
Secretary of the Commission

SB/hv
Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE RATES OF DELTA NATURAL GAS COMPANY, INC. ) CASE NO. 99-176

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

| | |
|---|---|
| AN ADJUSTMENT OF THE RATES OF DELTA NATURAL GAS COMPANY, INC. | ) CASE NO. 99-176<br>) |

ORDER

Delta Natural Gas Company, Inc. ("Delta") has applied for authority to adjust its rates for gas service to produce additional annual revenues of $2,551,797, an increase of 6.76 percent, and to establish a weather normalization adjustment ("WNA") clause and an Experimental Alternative Regulation Plan ("ARP"). By this Order, the Commission establishes rates for Delta that will produce additional annual operating revenues of $419,702[1] and approves the establishment of a WNA. We deny Delta's request to implement its proposed Experimental ARP.

COMMENTARY

Delta is a Kentucky corporation whose principal offices and place of business are located in Winchester, Kentucky. Delta purchases, sells, stores, transports and distributes natural gas to approximately 38,000 customers in 23 counties in central and eastern Kentucky.

[1] The base rates that the Commission establishes in this Order will generate additional revenues of $2,957,796. The inclusion of Delta's investment in the Canada Mountain gas storage facilities into rate base and its corresponding removal from Delta's gas cost recovery mechanism will reduce Delta's annual revenues from its gas cost recovery mechanism by approximately $2,538,094.

## PROCEDURE

On July 1, 1999, Delta filed its application for a rate adjustment. Delta's application includes proposals to establish a WNA clause and an ARP. To determine the reasonableness of the proposed rates, the Commission suspended the proposed rates until December 31, 1999, and initiated this proceeding.[2] Because Delta's proposal for an ARP was the subject of Case No. 99-046,[3] the Commission directed that the record of that proceeding be incorporated into the record of this case.[4] The Commission also established a procedural schedule for discovery and the submission of written testimony.

On July 7, 1999, Delta moved for consolidation of this proceeding, Case No. 99-176, with Case No. 99-046. After reviewing Delta's application and comparing the ARP proposed in Case No. 99-046 with the rate increase proposed in this proceeding, we found that several modifications in the ARP proposed in this proceeding render Delta's earlier proposal moot. We therefore directed that the proceedings in Case No. 99-046 be closed.[5]

The Commission has permitted the Attorney General ("AG") to intervene in this proceeding. No other person sought to intervene.

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[2] Order of July 30, 1999 at 2.

[3] Case No. 99-046, Delta Natural Gas Company, Inc.'s Application to Implement an Experimental Alternative Regulation Plan.

[4] Unless otherwise stated, all references in this Order refer to documents in Case No. 99-176.

[5] Order of August 5, 1999 at 3 – 4.

On October 29 and 30, 1999, the Commission held a public hearing on Delta's application. Following the parties' submission of written briefs on November 29, 1999, this case stood submitted for decision.

## TEST PERIOD

Delta proposes and the Commission accepts the 12-month period ended December 31, 1998 as the test period for determining the reasonableness of the proposed rates.

## VALUATION

Delta proposes a net investment rate base of $76,088,138.[6] Based upon the discussion below, the Commission finds that Delta's net investment rate base is $91,997,648.

### Utility Plant In Service

Delta reports its proposed test-period level of utility plant in service ("UPIS") as $114,965,626. It reaches this level by removing its investment of $14,323,170 in the Canada Mountain gas storage facilities ("Canada Mountain") from UPIS. Delta currently recovers this investment through its Gas Cost Recovery ("GCR") mechanism.[7]

Canada Mountain consists of a gas storage field and related facilities located in Bell County, Kentucky. Delta purchased the facilities in 1995 to ensure "a firm and

[6] Delta's Application, Vol. 1 at Tab 25.

[7] The AG uses Delta's proposed UPIS balance to calculate its proposed net investment rate base. See Direct Testimony of Robert J. Henkes at Schedule RJH-3.

more reasonably priced supply of gas to its southern system."[8] After its purchase of the facilities and the issuance of evidences of indebtedness to finance the purchase, Delta executed a lease agreement with Deltran, Inc. ("Deltran"), a wholly owned subsidary of Delta, under which Delta leased Canada Mountain to Deltran. Deltran in turn provides gas storage services to Delta. Deltran's rate for storage service is based on the cost incurred to provide the service. The rate is adjusted quarterly to reflect changes in its cost of service allowed for immediate rate recovery of capital improvements to the storage field as these improvements are made. Delta in turn recovers the cost associated with its payments to Deltran through its GCR.

When the Commission approved this arrangement, we did so as a temporary expedient to allow Delta to begin immediate recovery of its investment. The storage facility was intended to assist Delta in managing its gas supply, thereby lowering the cost of gas to Delta's customers. Allowing the recovery through Delta's GCR negated the need for frequent rate adjustment cases while the facility was being constructed and brought up to its required capacity. Delta's president has acknowledged that this rate-making treatment was never considered a permanent measure.[9]

The Commission finds that, because the construction of the Canada Mountain storage facilities is now completed,[10] the recovery of Delta's investment in these

[8] Case No. 95-098, The Application of Delta Natural Gas Company, Inc. for an Order Authorizing the Purchase and Financing of the Canada Mountain Gas Storage Field, Order (September 7, 1995) at 2.

[9] Transcript, Vol. I at 78.

[10] Construction of the facilities was completed in October 1997. See Delta's Response to the Commission's Order of September 14, 1999, Item 6a.

facilities should be through Delta's base rates and not through Delta's GCR. The transfer from the GCR to base rates will not have a significant impact on the overall rate charged to Delta's ratepayers. The Canada Mountain assets should be rolled into rate base at current levels since that is the amount that is currently being reviewed through the GCR. According to Delta's most recent GCR filing,[11] Delta's Canada Mountain investment is currently $16,834,563.[12] The Commission, therefore, has increased Delta's UPIS balance by this amount.

<u>Accumulated Depreciation</u>

Delta proposes to reduce rate base by test-period-end accumulated depreciation of $35,230,946.[13] It further proposes to increase accumulated depreciation by $20,212 to normalize the test-period level of depreciation expense by the test-period-end level of UPIS investment.[14] As Delta's investment in Canada Mountain will henceforth be reflected in Delta's rates as a component of Delta's rate base, the Commission finds that Delta's pro forma accumulated depreciation should further be increased by $1,009,700 to reflect Canada Mountain's accumulated depreciation as of July 31, 1999,

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[11] Case No. 97-066-H, Purchased Gas Adjustment of Delta Natural Gas Company (November 1, 1999). Test Period July 31, 1999.

[12]

| | |
|---|---|
| Gross UPIS | $ 17,278,017 |
| Unamortized Debt Issuance Cost | - 443,454 |
| Canada Mountain Investment | $ 16,834,563 |

[13] Delta's Application, Vol. 1 at Tab 25.

[14] Direct Testimony of John F. Hall at 4.

which was used in the most recent GCR filing. Delta's pro forma accumulated depreciation, therefore, is $36,260,858.

Cash Working Capital

Delta proposes to include in its rate base an allowance for cash working capital of $1,097,255 to reflect 1/8th of its pro forma operation and maintenance expenses, excluding the purchased gas cost.[15] Based upon its lower recommended pro forma operation and maintenance expenses and using the 1/8th formula, the AG proposes a cash working capital level of $1,050,255.[16] The Commission finds that, in the absence of any lead-lag study, the 1/8th formula should be used to determine Delta's level of cash working capital. After applying the 1/8th formula to the level of operating and maintenance expenses found reasonable herein, the Commission finds that an appropriate level of cash working capital is $1,087,080.

Prepayments

Delta proposes to include in its rate base the test-period-end level of prepayments in the amount of $106,884. Citing the Commission's use of a 13-month average balance to establish the appropriate level of prepayments in Delta's last general rate adjustment case,[17] the AG argues that a 13-month average balance of prepayments should be used and that Delta's proposed prepayments should be

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[15] Id. at 5.

[16] Posthearing Brief of the AG at 4.

[17] See Case No. 97-066, An Adjustment of General Rates of Delta Natural Gas Company, Inc. (Dec. 8, 1997) at 4.

increased by $100,451 to $207,335.[18] As the AG's proposal is consistent with past Commission practice and as Delta has not disputed the use of this methodology, the Commission accepts the proposed adjustment.

Materials and Supplies

Delta proposes to include in rate base the test-period-end level of materials and supplies totaling $451,812. The AG proposes to increase materials and supplies by $121,751 to reflect the 13-month average material and supplies balance.[19] Finding that use of a 13-month average is more consistent with past Commission practices, we accept the AG's proposed adjustment and include in rate base the 13-month average balance of materials and supplies of $573,563.

Gas In Storage

Delta proposes the test-period-end level of gas in storage totaling $265,579. Using the 13-month average balance to establish the level of gas in storage, the Commission finds that gas in storage should be valued at $263,856.

Unamortized Debt Issuance Costs

Delta proposes to decrease its test-period-end level of unamortized debt issuance cost of $3,650,173 by $541,248, or 14.83 percent. This proposal is based upon the percentage of test-period-end long-term debt balance attributable to Canada Mountain and is consistent with the Commission's decision in Delta's last general rate

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[18] AG's Brief at 4.

[19] Id.

case.[20] Insofar as we have determined that the Canada Mountain investment should now be recovered through Delta's base rates, we find that Delta's proposal should be denied.

Accumulated Deferred Income Taxes ("ADIT")

Delta originally proposed to reduce rate base by $8,436,725 to reflect the total test-period-end balance of all ADIT accounts. It subsequently acknowledged that rate base should be reduced by $9,103,630 to reflect the removal of ADIT components not allowed in Case No. 97-066.[21] Accordingly, we reduce rate base by the ADIT balance of $9,103,630.

Advances for Construction

Delta proposes, and the Commission accepts, a reduction to rate base by the test-period-end level of advances for construction in the amount of $220,060.

Customer Deposits

The AG proposes to reduce rate base by the test-period-end level of customer deposits of $594,863. He contends that customer deposits, like customer advances, are received at a rate greater than the amount refunded and that Delta has the use of this customer supplied capital. If interest on customer deposits is recognized as an expense, he contends, the principal (the customer deposit balance) must be recognized as a rate base reduction. In support of his position, he points to past Commission proceedings in which the Commission treated customer deposit balances as rate base

[20] Case No. 97-066, Order of December 8, 1997 at 5.

[21] See Delta's Response to the Commission's Order of September 14, 1999, Item 27.

reductions when treating the associated interest expense as a pro forma operating expense.[22]

Delta advances two arguments in response. It notes that its proposed treatment of customer deposits conforms to the Commission's decision in Case No. 97-066.[23] It further notes a difference between customer advances and customer deposits. Customer advances, Delta argues, directly relate to plant investment and are deducted from rate base because the utility does not have to supply the capital to support that amount of plant investment. Customer deposits, on the other hand, do not relate to UPIS or any other rate base item.[24]

In Case No. 97-066, the Commission included the interest on customer deposits in Delta's pro forma operating expenses, but did not reduce rate base by the customer deposit balance. We concede that our action was not consistent. The customer deposit balance and interest must both be included or excluded in determining the revenue requirement. Since customer deposits represent a liability to be repaid to the customer with interest,[25] the Commission generally has not recognized the deposits as readily available cost free capital. For this reason, the Commission finds that the AG's proposed adjustment should be denied. We further find that all interest associated with the customer deposits should be excluded from Delta's pro forma operating expenses.

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[22] AG's Brief at 5 - 6.

[23] Case No. 97-066, Order of December 8, 1997 at 6.

[24] Delta's Brief at 22 - 23.

[25] See KRS 278.460(1).

Summary

The Commission finds Delta's net investment rate base to be as follows:

| | |
|---|---|
| Utility Plant In Service | $131,800,189 |
| Accumulated Depreciation | ( 36,260,858) |
| Net Utility Plant In Service | $ 95,539,331 |
| Add: | |
| Working Capital Allowance | 1,087,080 |
| Prepayments | 207,335 |
| Materials and Supplies | 573,563 |
| Gas In Storage | 263,856 |
| Unamortized Debt Issuance Cost | 3,650,173 |
| Deduct: | |
| Accumulated Deferred Income Taxes | (9,103,630) |
| Advances for Construction | (220,060) |
| Net Investment Rate Base | $ 91,997,648 |

## CAPITALIZATION

Delta proposes to use a hypothetical capital structure consisting of 43.50 percent common equity, 48.43 percent long-term debt, and 8.07 percent short-term debt. This structure is based upon the test-period total capital balance adjusted to remove Canada Mountain and Delta's investment in subsidiaries. Delta argues that this hypothetical capital structure is supported by published research, is consistent with applicable law, and will help reverse the decline in the equity component of its capital structure.[26]

The AG opposes the use of a hypothetical capital structure. He argues that its use would represent a radical departure from past Commission rate-making practices. He notes that Delta's common equity problem stems in large measure from decisions of

[26] Delta's Brief at 6.

Delta's management. Before resorting to the drastic remedy of an imputed capital structure, he argues, the Commission should first employ remedies such as a weather normalization clause that will address matters outside of management's control. Such remedies may, he argues, obviate the need for more drastic remedies. He notes that Delta's equity problems did not occur suddenly and that any remedy must work in a gradual manner to correct those problems.

Instead of a hypothetical capital structure, the AG proposes a capital structure based on Delta's actual test-period-end structure adjusted to eliminate the equity associated with non-regulated subsidiaries and the capital associated with Canada Mountain. It consists of 29.80 percent equity, 60.17 percent long-term debt, and 10.02 percent short-term debt.[27]

The Commission agrees that Delta's equity problem occurred gradually. Between 1988 and 1998, Delta's equity ratio decreased from 45.8 percent to 31 percent of total capital.[28] One factor contributing to Delta's financial condition was Delta's inability in recent years due to warmer than usual weather conditions to earn its allowed return. Delta's rates are premised on the assumption that normal weather conditions will occur. Weather is certainly a factor outside of management's control.[29] To reduce the effects of weather, the Commission will approve the use of a WNA.

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[27] Direct Testimony of Robert J. Henkes at 4.

[28] Delta's Response to the Commission's July 15, 1999 Order, Item 2.

[29] Transcript, Vol. I at 30.

The Commission finds that management must bear some responsibility for Delta's current condition. Delta's president concedes that the decline in Delta's equity component is, in part, dependent upon the actions of management.[30]

The Commission finds that, before the drastic remedy of a hypothetical capital structure is used, other remedies must be given an opportunity to work. The rate stability that should arise from a weather normalization clause should also improve the relationship of equity to the other capital components. If these remedies prove unsuccessful, the Commission will consider the use of more drastic remedies. Until such time, however, the Commission finds that Delta's proposed hypothetical capital structure should be denied.

The Canada Mountain investment has been transferred from the GCR to Delta's base rates. To recognize the recovery of Canada Mountain in the base rates, the capital structure has been adjusted to reflect the July 31, 1999 investment, which is shown in Appendix A.

The Commission finds Delta's total capital structure to be as follows:

| | Amount | Percent |
|---|---|---|
| Long-Term Debt | $ 55,798,398 | 60.00 |
| Short-Term Debt | 9,294,956 | 10.00 |
| Common Equity | 27,903,425 | 30.00 |
| Totals | $ 92,996,779 | 100.00 |

## REVENUES AND EXPENSES

Delta reported actual net operating income of $6,214,670 for the test period. Delta proposed several pro forma adjustments to revenues and expenses to arrive at its

30 Id. at 29.

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[30] Id. at 29.

pro forma net operating income of $5,564,849. The Commission finds that the proposed adjustments are generally proper and acceptable for rate-making purposes with the following modifications:

Year End Customer Growth Adjustment

Revenue. In its application, Delta proposed an adjustment to increase revenue by $304,119 to recognize additional revenue that would have been generated if it had served the year-end number of customers for the entire test period. It subsequently increased this proposed adjustment to $423,668 to correct certain mathematical errors.[31] The Commission accepts Delta's revised adjustment.

Expenses. Delta proposes to increase operating expenses by $75,906 to reflect additional operating expenses associated with serving the test-year-end number of customers and supplying the related volumes. It calculates this adjustment by applying an operating ratio of 17.92 percent to the revenue adjustment. It arrived at this by dividing operation and maintenance expense (exclusive of gas supply costs and wages and salaries) by its normalized base rate revenues.

While generally accepting Delta's methodology, the AG argues that additional expenses not related to customer levels should be subtracted from operating and maintenance expense to determine the proper operating ratio. He proposed the removal of employee pensions and benefits, miscellaneous general expenses, regulatory Commission expense, property insurance and outside services employed, which results in an operating ratio of 3.62 percent.

[31] See Transcript, Vol. II at 87; Delta's Response to the AG's Information Request of August 11, 1999, Item 73.

The Commission finds that employee pensions and benefits and regulatory Commission expense do not vary with incremental customer sales, are unrelated to end of test year customer levels, and should be subtracted from operating and maintenance expense when computing the operating ratio. Removal of these expenses results in a 10.63 percent expense to revenue ratio and an expense adjustment of $45,036.

Temperature Normalization Adjustment

Delta proposes to increase revenue by $1,693,458 to reflect warmer than normal temperatures experienced during the test period. Delta's method of computing this adjustment is consistent with the methodology that it has used, and the Commission has accepted, in Delta's prior rate adjustment proceedings. The AG does not object to the proposed adjustment. The Commission accepts the proposed temperature normalization adjustment.

Wages and Salaries

Delta proposes to increase test-period-end wages and salaries by $116,199 to normalize its payroll to reflect the July 1, 1998 employee wage increases.[32] To reflect its current level of employees, Delta annualized the pay period ending December 31, 1998.[33]

The AG argues that Delta's proposed adjustment is a "gross" payroll adjustment and does not reflect amounts allocated to construction and subsidiaries. He proposes

[32] Direct Testimony of John F. Hall at 4.

[33] Delta's Response to the Commission's Order of September 14, 1999, Item 21(a).

to increase test-period wages and salaries by $85,964 to reflect only the portion of the payroll increase that will be charged to operation and maintenance expense.[34]

In response to a Commission request, Delta determined that, based on its employees' actual regular and overtime hours in 1998 and the July 1, 1998 wage rates, its pro forma gross salaries and wages are $6,213,582.[35] The Commission finds that, if capitalized wages of $1,595,398[36] and the subsidiary allocation of $6,000 are removed, Delta would have expensed only $4,612,184 of its $6,213,582 in gross pro forma salaries and wages. During the test period Delta's salaries and wages expense was $4,531,719,[37] or $80,465 less than the Commission's pro forma salaries and wages expense. Delta's controller has acknowledged that the appropriate level of payroll adjustment is $80,465.[38] Accordingly, we find that test-period wages should be increased by this amount.

Disallowed Accounts

In its application, Delta proposed to reduce test-period operating expenses by $142,711, to remove expenses that the Commission disallowed in its previous rate adjustment proceeding.[39] These expenses were advertising expenses of $10,755;

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[34] Direct Testimony of Robert J. Henkes at 24.

[35] Delta's Response to the Commission's Order of September 14, 1999, Item 23.

[36] Id.

[37] Delta's Application, Tab 30 (FERC Form No.2) at 355.

[38] Transcript, Vol. I at 199.

[39] Case No. 97-066, Order of December 8, 1997 at 12-15.

public and community relations expenses of $16,886; conservation program expenses of $48,913; lobbying expenditures of $4,279; marketing costs of $37,869; and administrative payroll expenses of $24,000 related to the forgiveness of a note owed by Delta's president.[40]

Stating that it erroneously removed the expenses related to the forgiven loan, Delta now asserts that the $24,000 should be included in allowable expenses.[41] To support the inclusion of this expense, Delta refers to a survey of total cash compensation for the chief executive officers of ten small gas utilities and asserts that its president's total compensation, including the loan forgiveness, is "uncompetitively lower than CEO compensation for other companies in the small gas company sector" and should therefore not be reduced.[42]

While Delta provides the results, it fails to provide any information to make a meaningful comparison of Delta and the 10 companies surveyed. Delta also fails to show the survey is representative of the gas industry. We have previously found that, given Delta's size and complexity, the base compensation paid to Delta's president is adequate.[43] Delta fails to present any evidence in the current proceeding to dispute our

[40] Delta's Application, Tab 25 at Schedule 4; Delta's Response to the Commission's Order of August 11, 1999, Item 30(c); Delta's Response to the Commission's Order of September 14, 1999, Item 25.

[41] Delta's Response to the Commission's Order of September 14, 1999, Item 25.

[42] Delta's Brief at 25.

[43] Case No. 97-066, Order of December 8, 1997 at 12.

earlier findings. We, therefore, accept the adjustments as originally proposed and decrease Delta's operating expenses by $142,711.

Canada Mountain

Delta proposes to reduce test-period expenses by $121,120 for costs related to Canada Mountain.[44] The AG proposes that an additional $35,918 in related Canada Mountain expenses be disallowed.[45] As we have included the Canada Mountain investment in Delta's base rates,[46] the Commission finds that both parties' adjustments should be denied.

Customer Deposits

Delta proposes to increase test-period expenses by $35,692 to include the interest on customer deposits in operating expenses.[47] As previously discussed,[48] the Commission has determined that it is inconsistent not to deduct the customer deposit balance from rate base while allowing the corresponding interest expense to be included in Delta's operating expenses. For this reason, Delta's proposed adjustment to move interest on customer deposits "above-the-line" should be denied.

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[44] Delta's Brief at 25.

[45] Direct Testimony of Robert J. Henkes at 32.

[46] See supra pp. 4 – 5.

[47] Direct Testimony of John F. Hall at 4.

[48] See supra pp. 8 – 9.

Medical Expense Adjustment

In its application, Delta proposed to increase test-period expenses by $77,561 to reflect the recovery of funds from Delta's stop-loss insurance coverage that was applicable to 1997.[49] Delta's controller testified at the hearing, however, that this adjustment had not been reduced to reflect the amounts allocated to construction and subsidiaries and should be reduced to $57,380 to reflect such allocation.[50] The Commission accepts the revised medical expense adjustment of $57,380.

Rate Case Expense

Delta proposes to increase test-period expenses by $48,333 to reflect amortizing its estimated rate case expense of $145,000 over a 3-year period.[51] The AG proposes a reduction of $19,920 in operating expenses to eliminate $24,960 of rate case expense amortization for Case No. 97-066; to reduce rate case expense amortization for the current case to $29,000; and to remove Delta's cost to participate in the Department of Transportation's ("DOT") Pipeline Safety training program in 1999 in the amount of $23,960.[52]

The AG argues that Delta's rate case expense should be normalized rather than amortized. He argues that the timing of a rate case is a matter entirely within the

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[49] Direct Testimony of John F. Hall at 4.

[50] This allocation is made by multiplying the gross adjustment of $77,561 by the operation and maintenance ratio of 73.98 percent. See Transcript, Vol. I at 185.

[51] Direct Testimony of John F. Hall at 4.

[52] AG's Brief at 9 - 13.

discretion of the utility. Ratepayers, he asserts, should not therefore have to bear the cost of two rate cases merely because Delta chose to seek rate relief before the amortization period for Delta's prior rate case expenses had completely run.[53]

Delta argues in response that the AG's normalization methodology would deny it the recovery of expenses already authorized by the Commission. It notes that the proposal is inconsistent with the AG's recommendations in Case No. 99-046, ignores the conceptual differences between amortization and normalization, and violates the Commission's Order in Case No. 97-066.[54]

Finding that the AG's proposal to exclude Delta's allowed rate case expense from Case No. 97-066 is unlawful and unreasonable, we reject the proposal. Implicit in the AG's proposal is the concept that utilities should be discouraged from seeking rate adjustments by preventing "carte blanche dollar-for-dollar recovery of multiple rate case expense each time it comes in."[55] Such an argument fails to take into account KRS 278.180, which permits a utility to apply for rate adjustments without limitation or restriction.[56] Moreover, it conflicts with the longstanding principle that rate case expenses are appropriately included in utility rates. See West Ohio Gas Co. v. Public

[53] Id. at 10.

[54] Delta's Brief at 21.

[55] AG's Brief at 10 - 11.

[56] See Case No. 95-554, Application of Kentucky-American Water Company to Increase Its Rates (Sept. 11, 1996) at 41 ("There is nothing in KRS Chapter 278 that authorizes the Commission to adopt a disincentive to, in effect, penalize a utility for exercise its right to seek rate relief").

Utilities Comm'n, 294 U.S. 63, 74 (1935) (holding that rate case expenses "must be included among the costs of operation in the computation of a fair return" and that "[t]he charges of engineers and counsel, incurred in defense of its security and perhaps its very life, were as appropriate and even necessary as expenses could well be").

The AG's policy, moreover, would have the unintended consequence of discouraging utilities from seeking rate relief. For example, the record in this case demonstrates that Delta's reluctance to seek rate relief in a timely manner has had a negative effect on its financial condition and contributed to the erosion of the equity component of its capital structure.

The AG also contends that the Commission should exclude from rate recovery any expenses associated with Case No. 99-046 and with Delta's Experimental ARP.[57] The AG argues that Delta has not requested recovery of these expenses, that he has not had adequate opportunity to review these expenses, and that the proposed Experimental ARP was for the primary benefit of shareholders.

The Commission finds no merit in these arguments. We note that Delta's application in this proceeding included a revised version of its Experimental ARP and that much of the evidence regarding this plan was originally submitted in Case No. 99-046. While Delta certainly intended for its proposal to benefit its shareholders, the Commission fails to discern how Delta's motive in Case No. 99-046 differs in any fashion from its motives in a general rate adjustment proceeding. In each instance, the

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[57] Id. at 11 – 13.

utility's paramount interest is to protect the interests of its shareholders. Moreover, the AG presents no legal authority to suggest that Delta's presentation of its Experimental ARP falls outside the holding of West Ohio Gas Co.

The Commission finds that, based upon Delta's most recent cost filings,[58] Delta incurred expenses of $35,518 to prosecute Case No. 99-046 and expenses of $183,235 to prosecute this proceeding. We further find that these costs should be amortized over a 3-year period to reflect the normal interval between Delta's general rate adjustment applications. Accordingly, rate case expense should be increased by $72,918.

The AG asserts that Delta recorded the 1998 and 1999 DOT Pipeline Safety program costs in its test-period operating expenses. The AG recommends that Delta's test-period operating expenses be reduced by $23,960 to remove the "out-of-period" expense item and to avoid a doubling of the expense for the same program. The Commission finds that the AG's adjustment is reasonable and, therefore, reduces operating expenses by $23,960.

Public Service Commission Assessment

The Commission has increased Delta's Public Service Commission assessment by $3,449 to reflect the impact of the Commission-approved revenue increase on this expense.

[58] Delta's Response to Staff Hearing Data Request to John F. Hall, Item 6.

Pension Expense

Delta incurred $292,818 in pension expense during the test period. The AG proposes to decrease this expense by $82,599 to reflect the findings of the actuary report of April 1, 1999 and the use of the operation and maintenance ratio of 73.98 percent.[59] The Commission finds that Delta must invest $267,238 in its employee pension fund for the 12-month period ending April 1, 2000.[60] This amount combined with the test-period fees paid to Hand and Associates, Delta's actuary, the American Industry Trust Company, Delta's trustee, and the Pension Benefit Guaranty Corporation of $46,354[61] results in a pro forma pension expense of $307,592, or $14,773 above Delta's test-period level. The Commission has applied the 73.98 percent operation and maintenance ratio to the gross pension adjustment of $14,773 to arrive at our pension expense adjustment of $10,929.

401(k) Expense

The AG argues that Delta's 1998 401(k) expense includes a reclassification of the pension expense due to an account distribution correction made for a trustee for the year 1997. Applying the operation and maintenance ratio of 73.98 percent to the $18,736 reclassification, the AG proposes to reduce 401(k) expense by $13,861. The Commission accepts the proposed adjustment.

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[59] Direct Testimony of Robert J. Henkes at 25.

[60] Delta's Response to Staff Hearing Data Request to John Brown, Item 1.

[61] Rebuttal Testimony of John B. Brown at 7.

Bad Debt Expense

Contending that Delta's test-period bad debt expense is abnormally high, the AG recommends that bad debt expense be adjusted to reflect a bad debt-to-revenue ratio of 0.67 percent, Delta's average bad debt ratio for the 4-year period ending 1998. Using the 0.67 percent debt-to-revenue ratio and its recommended base revenues and GCR revenues, the AG recommends a reduction of $95,204 in test-period bad debt expense for a total bad debt expense of $250,666.[62]

Delta argues that the AG's proposed adjustment is "a post test year adjustment" that should be rejected. It futher contends that the AG chose an expense item that might decrease because of management's effort to control bad debt expense and then projects a post test year decrease in this expense. Delta argues that the historical data for the past 4 years shows that the AG's proposed bad debt expense is unreasonable on a going forward basis.[63]

Delta's bad debt expense for the 12-month periods ending October 31, 1998 and October 31, 1999 was $353,870 and $213,385, respectively.[64] This reduction in bad debt expense strongly suggests that the implementation of a more aggressive collection program has significantly affected collections and supports the AG's arguments underlying the proposed bad debt adjustment.

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[62] AG's Brief at 14.

[63] Delta's Brief at 22.

[64] Delta's Response to Staff Hearing Data Request to Steve Seelye, Item 1.

The Commission finds that the AG's proposed debt-to-revenue ratio of 0.67 percent is reasonable. Using this ratio and the pro forma base revenues and GCR revenues found reasonable herein, the Commission has calculated an adjustment to reduce bad debt expense by $90,810.

Miscellaneous

The AG proposes to reduce Delta's test-period operating expenses by $30,114 to remove spousal travel expenses of $404, meals and entertainment expenses of $805 for golf outings, employee membership dues of $1,274, and an abnormal booking of $27,631 that is related to a settlement of a sales tax audit.[65]

The Commission finds that the employee-related expenses totaling $2,483 are not appropriate for rate recovery and should be excluded for rate-making purposes. While employee-related expenses may benefit employer/employee relations, Delta's ratepayers should not bear these costs. We have, therefore, reduced Delta's test-period expenses by $2,483 to eliminate these expenses.

As to the sales tax audit expense, Delta argues that this expense is typical of many expenses that Delta incurs on an ongoing basis. Delta further argues that various regulatory agencies constantly audit or review its records and that payments of settlement amounts should not, therefore, be considered unusual.[66] In response the AG

[65] AG's Brief at 15.

[66] Rebuttal Testimony of John B. Brown at 8.

points to Delta's admission that "[t]he only abnormal booking for the test year, 1998, was Delta's settlement of $27,631 in a sales tax audit."[67]

The Commission finds that the AG's proposed adjustment to eliminate $27,631 in sales tax audit costs should be accepted. While Delta may have audits or review on a frequent basis, it fails to present any evidence to demonstrate that the sales tax audit will be an annual recurring expense.

Depreciation Expense

Delta proposes to decrease test-period depreciation expense by $20,212 to reflect the test-period level of UPIS investment.[68] Based upon our review of Delta's depreciation schedule, we find that this adjustment should be accepted. As previously discussed, Delta's investment in Canada Mountain is being included in the base rates. To accomplish this objective, the Commission has increased depreciation expense by $454,935, the July 31, 1999 level of annual Canada Mountain depreciation expense. The amount reflects the amount of depreciation currently being recovered through Delta's GCR and is based upon the most recent cost information submitted to the Commission.

Payroll Taxes

Delta proposes to increase payroll taxes by $8,937 to reflect the effect of its proposed payroll adjustment on payroll taxes. The AG proposes to adjust Delta's

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[67] Delta's Response to the AG's Information Request of August 11, 1999, Item 26.

[68] Direct Testimony of John F. Hall at 4.

payroll increase by the operation and maintenance ratio of 73.98 percent, which results in a decreased payroll tax adjustment of $6,611.[69] The Commission finds that payroll taxes should be increased by $6,188 to reflect the payroll adjustment determined to be reasonable herein.

Property Taxes

Delta proposes to remove $47,147 in property taxes that are associated with Canada Mountain. The AG proposes a property tax adjustment of $113,904 to reflect the removal of Canada Mountain from rate base. The Commission finds that, as the Canada Mountain investment has not been removed from Delta's test-period operations, both adjustments should be denied.

Income Tax Expense

Delta's proposed income tax expense is based upon a 39.445 percent blended federal and state income tax rate applied to adjusted after tax equity return based on Delta's proposed expenses.[70] The AG proposes to adjust Delta's income tax methodology to reflect the investment tax credit amortization of $71,000 and the $21,000 in amortization of deferred income taxes resulting from the change in the federal statutory tax rate.[71] Accepting the AG's proposed adjustments and applying the composite tax rate to revenues and expenses found reasonable herein, the Commission finds that Delta's adjusted income tax expense is $768,068.

[69] AG's Brief at 16.

[70] Direct Testimony of John F. Hall at 5.

[71] AG's Brief at 17.

### Interest Synchronization

Delta proposes a reduction of $1,395,455 in test-period interest expense to reflect the hypothetical debt levels and the actual interest rates. Applying Delta's recommended weighted cost of debt to its proposed rate base, the AG proposes a reduction of $727,730. Delta's proposed interest synchronization methodology is based on the assumption that the revenue requirement determination is based on the capital structure.

In Case No. 97-066, the Commission applied Delta's weighted cost of debt to the net investment rate base to achieve the correct level of interest expense for rate-making purposes.[72] Delta has not presented any evidence to persuade the Commission to abandon this approach. Accordingly, Delta's weighted cost of debt should be applied to the net investment rate base to achieve the correct level of interest expense for rate-making purposes. Therefore, the Commission has increased test-period interest expense by $159,959.

### Summary

The Commission finds Delta's adjusted operations are as follows:

| | Reported Test-period | Pro Forma Adjustments | Adjusted Test-period |
|---|---|---|---|
| Operating Revenues | $ 34,857,742 | $(14,063,077) | $ 20,794,665 |
| Operating Expenses | 28,643,072 | (13,943,252) | 14,699,820 |
| Net Operating Income | $ 6,214,670 | $( 119,825) | $ 6,094,845 |
| Interest Expense | 4,509,474 | 159,959 | 4,669,433 |
| Net Income | $ 1,705,196 | $( 279,784) | $ 1,425,412 |

[72] Case No. 97-066, Order of December 8, 1997 at 18.

## RATE OF RETURN

Cost of Debt

Delta proposes a 7.4786 percent cost of long-term debt based on its embedded cost of long-term debt as of the end of December 1998. It originally proposed a short-term debt cost rate of 5.41 percent, its cost of short-term debt capital as of June 21, 1999. The AG's updated testimony accepted Delta's debt costs as proposed. Delta subsequently revised its short-term debt cost to reflect its current short-term debt cost rate of 5.89 percent. The Commission finds that Delta's cost of long-term debt should be 7.4786 percent and its cost of short-term debt should be 5.89 percent.

Return on Equity

Delta proposed a return on equity ("ROE") of 11.9 percent based on its proposed use of a hypothetical capital structure consisting of 43.50 percent common equity, 48.43 percent long-term debt, and 8.07 percent short-term debt. In the alternative, Delta proposed an ROE of 13.9 percent if its test year capital structure consisting of 29.80 percent common equity, 60.18 percent long-term debt, and 10.02 percent short-term debt is used.

Delta contends that its actual level of equity capital is so low, its revenue requirements should be based on a hypothetical equity level that is more representative of the average equity level for natural gas local distribution companies ("LDCs"). Delta used information reported for 29 LDCs in an Edward Jones report entitled Natural Gas Industry Summary Monthly Financial & Common Stock Information as the basis for its proposed 43.50 percent hypothetical common equity level. The mean equity level of those firms is 43.2 percent. The median is 43.9 percent. Delta asserts that use of the hypothetical capital structure will compensate for the relatively low equity level and the related risk that investors associate with investing in Delta stock. In the alternative, Delta proposes that the Commission compensate for the additional risk by granting Delta a higher return.

Delta performed a Discounted Cash Flow ("DCF") analysis to estimate its required ROE. The constant growth DCF model using Delta's annual dividend, current stock price, as well as its 52 week high and low prices, and Delta's growth rates obtained from analysts' reports, yielded a range of results from 8 percent to 9.93 percent. Substituting an expected industry growth rate obtained from <u>Cost of Capital Quarterly</u> by Ibbotson Associates in the calculations of the constant growth DCF model produced ROE estimates in a range of 11.7 percent to 12.41 percent. Using the two-stage form of the DCF model, which incorporates analysts' growth rates for Delta for the first five years and the industry average growth rate thereafter, produced results ranging from 10.20 percent to 12.05 percent.

Delta performed a risk premium analysis to estimate the required ROE. The risk premium analysis, which was performed for both short and long horizons, produced ROEs of 13.91 percent and 14.08 percent. Delta also used the Capital Asset Pricing Model ("CAPM") to adjust the risk premiums for the market as a whole to estimate Delta's ROE. The CAPM calculated by Delta produced an ROE of 10.48 percent, which Delta adjusted upward by adding a size premium of 260 basis points which produced an ROE of 13.08 percent. Using different beta coefficients, Delta calculated size-adjusted ROEs in a range of 11.88 percent to 15.08 percent.

Citing the rural nature of its service territory, Delta proposes that the Commission establish an ROE of 11.9 percent, which is near the top of the range produced by its DCF analysis. It further proposes that the Commission add a 2 percent leverage adjustment if a hypothetical capital structure is not used, resulting in a 13.9 percent ROE based on its test-year-end capital structure.

The AG recommends an ROE of 8 to 9 percent if Delta's proposed Experimental ARP is approved, an ROE of 10 to 11 percent if the Experimental ARP is rejected and the proposed WNA is adopted, and an ROE of 10.25 percent to 11.25 percent if both are rejected. The AG opposes the use of a hypothetical capital structure, arguing that a hypothetical capital structure is "a fiction that simply does not exist," and that the capital structure is "a management choice" which should not receive a "bonus" return.[73]

The AG also performed DCF, CAPM, and Bond Yield Risk Premium analyses. In performing these analyses, the AG used information that is specific to Delta, as well as data from five comparable gas distribution companies. The five companies are among the 23 investor-owned distribution companies that are listed in Value Line. They are listed on the New York Stock Exchange, had total assets in 1998 valued at less than $1 billion, and have net sales to total assets ratios more nearly similar to Delta than the other 18 companies listed in Value Line. Other measures used in the selection process for the five comparable companies related to financial leverage, namely the common equity ratio and ratio of total liabilities to total assets.

[73] Testimony of Carl G. K. Weaver at 8.

The AG stated that the comparison companies are larger than Delta and therefore less risky to the extent that size affects risk and that Delta is more risky because of its greater amount of long-term debt. On a relative basis, however, the AG points out that the comparable companies have more current liabilities than Delta, a factor that mitigates the financial risk difference. In performing a cash flow analysis of Delta and the five companies, the AG concluded that Delta's cash flow coverage of interest was very similar, though somewhat lower. The AG made the same characterization of Delta's cash flow of dividend coverage, although Delta's coverage ratio was slightly higher than that of the other companies. Delta was determined to be more likely to require external equity financing than the other companies, but also to have a very high quality of earnings due to its cash flow coverage of net income. The AG considered Delta to be of nearly the same risk as the five-company group from a cash flow perspective.

The AG also compared published risk measures for Delta and the five companies. As reported by Standard and Poor's, Delta's Beta is .02 while the average Beta for the five companies is .31, indicating that Delta has less systematic risk. Delta was ranked as having a financial strength of 32 as opposed to an average ranking for the five companies of 68. The AG concludes that the published market measures show that the five companies are less risky than an average company and that because Delta is similar to the five companies, it is also less risky than an average company. If Delta's proposed Experimental ARP is not approved, the AG concludes, Delta's cost of equity will be higher than the cost rate for the five companies.

The AG presented equity cost estimates for the five companies.[74] The DCF analysis performed on behalf of the AG produced a range of ROEs of 7.4 percent to 10.7 percent. The CAPM analysis produced a range of 9 percent to 11.1 percent. The AG's Bond Yield Risk Premium analysis produced a range of 9.9 to 10.9 percent. The AG concludes that the cost of equity for the five companies averages 9.75 percent to 10.75 percent, and raises the range by 50 basis points to account for Delta's greater risk. The resulting range is 10.25 to 11.25 percent, which the AG recommends if the hypothetical capital structure is rejected and neither the Experimental ARP nor the WNA are approved.

After reviewing the record and the analyses performed by both parties, the Commission finds that a hypothetical capital structure is not appropriate in this case for rate-making purposes. Delta's equity ratio in its capital structure has been below the industry average of 43.2 percent quoted by Delta since 1994.[75] Although the approved equity ratio of 30 percent is somewhat below the 36.25 percent approved in Delta's last rate case, it is not sufficiently low to justify the use of a hypothetical capital structure or an ROE of 13.9 percent. Delta's proposed ROE is based on a DCF analysis which uses market price data, and the data specific to Delta should already reflect investors' expectations regarding its capital structure.

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[74] Testimony of Carl G. K. Weaver at 1 – 5.

[75] Delta's Response to the Commission's Order of July 15, 1999, Item 2, Schedule 1.

The Commission acknowledges that Delta's service area is largely rural. We have always taken this factor into account when considering the appropriate ROE for Delta. This factor, as was Delta's then lower-than-average equity component in its capital structure, was reflected in the 11.6 percent ROE that we approved for Delta in Case No. 97-066.

The Commission acknowledges that weather is an element that significantly affects an LDC's earnings. Weather's effect on earnings is specifically discussed in the Hilliard Lyons and Edward Jones reports.[76] The WNA approved in this Order will mitigate the effect of weather on Delta's earnings. Ordinarily, the stabilizing effect of a WNA would be sufficient cause to award a lower return to a utility. We find, however, that Delta's returns over recent years have eroded its financial condition to the point that it would not be reasonable to lower Delta's ROE at this time. Furthermore, we are not persuaded that the ROE range that the AG proposes is adequate to preserve Delta's financial integrity and to enable it to attract capital.

The Commission, having considered all the evidence, including current economic conditions, finds that an ROE in the range of 11.1 to 12.1 continues to be fair, just, and reasonable for Delta. This range will allow Delta to attract capital at a reasonable cost and to maintain its financial integrity, ensuring continued service. It will provide for necessary expansion to meet future requirements, and result in the lowest possible cost to ratepayers. A return of 11.6 percent will best meet the above objectives.

[76] Delta's Response to the Commission's Order of August 11, 1999, Item 53.

Rate of Return Summary

Applying the rates of 7.4786 percent for long-term debt, 5.89 percent for short-term debt, and 11.6 percent for common equity to the capital structure approved produces an overall cost of capital of 8.556 percent. The Commission finds this overall cost of capital to be fair, just, and reasonable.

## REVENUE REQUIREMENTS

Based upon the Commission's findings and determinations herein, Delta requires an increase in revenues of $2,957,796, determined as follows:

| | |
|---|---|
| Net Investment Rate Base | $ 91,997,648 |
| Rate of Return | x 8.5556% |
| Required Operating Income | $ 7,870,951 |
| Adjusted Operating Income | - 6,094,845 |
| Revenue Deficiency | $ 1,766,106 |
| Gross-up Factor[77] | x1.66532608 |
| Required Increase, Inclusive of Income Taxes, PSC Assessment and Uncollectibles | $ 2,957,796 |

## COST-OF-SERVICE STUDY

Delta presented a fully allocated class cost-of-service study based on its embedded costs for the test period. The objective of a cost-of-service study is to determine class rates of return on rate base at present and proposed rates. A cost-of-service study may also be used to guide the Commission in allocating the revenue requirements among rate classes. Generally, Delta's cost-of-service study indicates that, at present rates, the residential class has a rate of return substantially less than the

[77] The Commission's gross-up factor includes allowances for uncollectibles and the PSC Assessment.

overall system average rate of return. Other rate classes are either near or above the system average. Delta used the results to design rates to reflect movement toward a better balance between service class rates of return while according recognition to the marketplace, customer acceptance and the theme of gradualism.[78]

Instead of a minimum system method, Delta uses the zero-intercept methodology to classify distribution mains into customer and demand components. The Commission has historically found that the zero-intercept methodology is an acceptable way to divide distribution main costs into demand-related and customer-related components and is statistically and theoretically more sound and less subjective than the minimum system method, in which a minimum size main must arbitrarily be chosen in order to determine the customer-related component.

The AG counters Delta's cost-of-service study on two fronts. First, he argues that Delta improperly used the weighted least squares in applying the zero intercept methodology. Second, he contends that no distribution mains costs should be assigned as customer-related costs. As a conservative approach, he argues that distribution mains should be allocated 50 percent on the basis of average demand and 50 percent on peak demand. In his cost-of-service study, the AG applied this same allocation to transmission mains along with other minor changes not previously specified. The Commission is concerned with the AG's approach, wherein assumptions are asserted without adequate support. However, since the AG chose not to use his findings in his

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[78] Delta's Brief at 33.

proposed revenue allocation, no undue consequences result from this overly conservative approach.

The Commission agrees that the results of a cost-of-service study are best used as a guide for revenue allocation and rate design. As Delta's study is consistent with prior studies accepted by the Commission, we will use it as a guide for revenue allocation and rate design. However, Delta is hereby put on notice that, in the future, better support must be filed including but not limited to a user-friendly study model (preferably in electronic form) accompanied by an instruction manual, the assumptions of the model, the inputs (variables and data), and the results. Such supporting documentation is necessary to facilitate complete analysis of all facets of the model.

## REVENUE ALLOCATION

Delta proposes to shift revenue from its general service and interruptible customers to its residential customers, but to a lesser degree than suggested by its cost-of-service study. Its proposed rates, Delta asserts, establish a reasonable balance between its cost-of-service study and the realities of the current marketplace. Delta further asserts it must make its general service rates more competitive or risk even more large volume customers switching to interruptible service. Delta stresses the importance of the revenue contribution from these large volume customers because of the high load factors and revenue stability that they create.

The AG opposes Delta's revenue allocations. He presents an alternative cost-of-service study[79] and argues that Delta's proposed concessions to the large commercial

[79] Direct Testimony of Richard A. Galligan, Exhibit RAG-1.

and interruptible class are unnecessary because interruptions in service to interruptible customers have been infrequent in recent years.[80] Although the results of his cost-of-service study support varying percentage rate increases among Delta's customer classes, the AG proposes an equal percentage increase for all customer classes.

In making our evaluation, the Commission recognizes that the natural gas industry has undergone major changes in recent years. As a result of these changes, large volume end-users, mainly industrial customers, have sought out their own gas supplies at prices less than the LDC's price for its system supply gas. These circumstances represent a significant departure from the time when all customers were essentially captive and few reasons existed to consider costs as a major factor in allocating revenues and designing rates. Regulation in this earlier era resulted in services that were often priced at less than the cost of service to residential customers and priced at more than the cost of service to commercial and industrial customers. Conventional wisdom held that, because commercial and industrial customers could pass along price increases to their customers, it was the better policy to price services to those customers above cost while pricing services to residential customers below cost. Today's competitive environment no longer supports such thinking and requires a restructuring of Delta's rates.

Delta's rate restructuring involves the allocation of non-gas, or base rate revenues. The Commission finds that the firm customer classes, at present rates, are not making an adequate contribution to Delta's overall rate of return and that, to

[80] Id. at 24-25.

increase that contribution, the full amount of the increase granted herein should be allocated to those customer classes.

The Commission also finds that rates to the interruptible classes should be reduced. The Commission concurs with the AG that Delta's interruptible customers, with their non-captive status, impose a greater level of risk to Delta than firm, essentially captive customers. This risk translates into required higher rates of return from those classes that Delta reflected in its cost-of-service study. The Commission finds that reducing the base rate revenue contribution for the interruptible rate classes recognizes the greater risks attendant with serving these classes and is consistent with the moderate, gradual approach to rate restructuring the Commission has followed in recent gas rate cases.

## RATE DESIGN

### General Service

Delta proposes to reduce the customer charge for small commercial customers from $18.36 to $17.00, to increase the customer charge for industrial customers from $25.00 to $50.00, and to increase the customer charge for interruptible customers from $200.00 to $250.00. Although its cost-of-service study shows that the residential customer charge does not fully recover the related customer costs, Delta proposes to maintain its residential customer charge at $8.00. This latter action, Delta asserts, reflects its sensitivity to the effect of higher rates for its residential customers. It will therefore move toward its full cost of service in this case by increasing commodity charges only.

Delta's cost-of-service study shows that the percentage increase to the small commercial class should be smaller than the residential increase, yet the present monthly customer charge is more than twice the customer charge for the residential class. The proposed rates will result in an increase for the small commercial customer class that is smaller than the increase for the residential class and will move the small commercial customer charge toward the residential customer charge.

Currently Delta's tariff lists all customer classes under one heading entitled "General Service." The Commission finds that Delta's general service rate should be restructured into four categories: residential, small non-residential general service, large non-residential general service, and interruptible service. We further find that residential service should be reduced to one usage block and small non-residential general service to three usage blocks. Neither Delta nor the AG opposes such restructuring.

The Commission further finds that the rates set out in Appendix B will produce the additional revenues granted herein and increase Delta's revenues by 8.44 percent. The rate changes, by customer class, produce increases of 12.20 percent and 9.61 percent for residential and small non-residential general service, respectively, while producing a 4.10 percent increase for large non-residential general service.

Gas Cost Adjustment

Moving Canada Mountain costs from Delta's Gas Cost Adjustment ("GCA") to its base rates requires an adjustment to the GCR factor that the Commission approved in Case No. 97-066-H. This adjustment will reduce the GCR from $3.9194 per MCF to $3.2071 per MCF effective January 1, 2000. This decrease in the GCR factor is an offset to the increase in base rates associated with the recovery of Canada Mountain costs. The GCR decrease is slightly greater than the base rate increase associated with Canada Mountain costs due to the current capital structure being different than that included in Delta's past GCA filings. However, Delta's capital structure, as reflected in this Order, would have been reflected in Delta's next GCA filing, which would have produced the same net decrease in rates, all other things being equal.

WNA Tariff

Delta proposes a WNA tariff to adjust for the significant effects that weather has on its earnings and return on equity. Delta's proposed WNA requires a base rate adjustment each month from December through April based on normal weather conditions. The WNA is intended to stabilize revenues and customers' bills by adjusting the base rate portion of customer bills to the levels that would exist under normal temperature conditions. Delta argues that, although a temperature normalization adjustment is historically allowed in rate cases, without a WNA mechanism it remains subject to drastic fluctuations in earnings and in its return on equity due to temperature variations.

The Commission finds that Delta's proposed WNA should be implemented as a pilot to be effective for the remainder of the current heating season and for the 2000-2001 and 2001-2002 heating seasons. We further find that Delta should be required to file annual reports on the operation of its WNA after each heating season. Delta may, by formal application, seek the Commission's approval to extend the pilot or to implement the WNA on a permanent basis after conclusion of the pilot. Such an application shall be made at the time Delta files its annual WNA report covering the 2001-2002 heating season.

## EXPERIMENTAL ARP

In its application, Delta proposes to implement an ARP on an experimental basis for a period of three years. Delta states that the ARPs purpose is to provide an alternative regulatory process for adjusting gas service rates. Delta's stated goal in establishing this mechanism is to provide an orderly and expeditious process for automatically making rate adjustments to keep Delta's rate of return within the range authorized by the Commission.[81]

Delta's ARP consisted of three components: an Annual Adjustment Component ("AAC"), an Actual Adjustment Factor ("AAF"), and a Balancing Adjustment Factor ("BAF").[82] The AAC would adjust base rates based on Delta's financial budget for the upcoming fiscal year. The level of the rate adjustment would depend upon the return projected to be earned based on Delta's financial budget. If projected revenues do not cover Delta's budgeted costs and produce a return at the midpoint of its authorized return on equity range, Delta's rates would be adjusted through the AAC to produce the necessary additional revenues.

The proposed ARP contains two limitations on any rate adjustment. First, Delta, with Commission approval, could reduce the annual revenue deficiency amount otherwise charged to customers if Delta determined that the mechanism would increase rates to a noncompetitive level. Second, the AAC could not exceed 5 percent of Delta's total utility revenues.

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[81] Case No. 99-046, Letter from John F. Hall, Vice President of Finance, Delta Natural Gas Company, to Helen C. Helton (February 5, 1999) at 3.

[82] See Delta's Application, Tab 7 at Sheet 30.

After the AAC has been in effect for a full year, the AAF would be used to perform a "true-up" calculation based on the actual return earned for the fiscal year. Through the application of the AAF Delta's rates would increase or decrease on a prospective basis, depending upon whether the utility's actual return on equity, for the current year, failed to meet or exceeded the range that the Commission found fair, just and reasonable. After the second year of the ARP's operation, and each year thereafter, the BAF would be used to true-up each year's adjustment to the AAF and to reflect any over- and under-recoveries realized through the application of the AAF and of the BAF for the preceding 12-month period.

Delta's ARP includes certain "performance-based controls." The first mechanism compares the company's actual non-gas supply Operations and Maintenance ("O&M") expenses per customer to the approved rate-case-level of non-gas supply O&M expenses on a per customer basis, adjusted for changes in the Consumer Price Index for Urban Consumers ("CPI-U"). If Delta's actual non-gas supply O&M expenses per customer fall within a 1.5 percent band of the indexed level of expenses, then actual O&M expenses are used to compute the earned return on common equity achieved in the most recent fiscal year for purposes of calculating the AAF. If Delta's actual costs are less than the indexed O&M by more than 1.5 percent, Delta would be allowed to increase its actual expenses by 50 percent of the amount by which the actual expenses are below 98.50 percent of the indexed O&M expenses. Conversely, if Delta's expenses exceed the indexed O&M expenses by more than 1.5 percent, Delta would be limited to including only 50 percent of the expenses above 102.5 percent of the indexed O&M expenses.

The second mechanism places a 60 percent cap on the amount of common equity that can be included in Delta's total capitalization for purposes of computing the AAF. Delta's current equity ratio is approximately 30 percent.

Delta's ARP is modeled upon Alabama Gas Company's ("Alagasco") Rate Stabilization and Equalization Plan ("RSE Plan").[83] There are, however, several differences. Delta's plan does not include quarterly adjustments. Unlike Delta's ARP, the Alagasco plan apparently does not fully reconcile budget to actual results. Annual increases in the Alagasco plan, furthermore, are capped at 4 percent of actual prior year's operating revenues as compared to Delta's cap of 5 percent.

Alagasco's plan allows rate decreases when the actual ROE is above the authorized ROE, but does not allow for rate increases when the actual ROE is below the authorized ROE. Delta's plan includes provisions for rate decreases when the actual ROE is above that authorized and for rate increases when the actual ROE is below that authorized. The "Indexed O&M Expenses" in Alagasco's plan are based on the company's prior year's actual O&M expenses increased by one year's worth of CPI inflator as compared to Delta's proposal to apply the CPI inflator annually to the amount allowed in its most recent rate proceeding. Alagasco's plan requires the utility to return to ratepayers 75 percent of any actual O&M expenses that are incurred in excess of the "Indexed O&M Expenses," plus 1.25 percent. Delta's plan returns 50 percent of such overruns to ratepayers.[84]

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[83] Case No. 99-046, Delta's Response to the Commission's Order of June 4, 1999, Item 20.

[84] Case No. 99-046, Direct Testimony of Robert J. Henkes at 26.

Delta asserts that the ARP would ensure that Delta's earned rate of return falls within the Commission-authorized range and that the ARP is a more gradual approach to rate-making than is accorded under traditional regulation. Delta further asserts that the ARP would result in a less adversarial rate-making process and that it would be less resource intensive and less costly for all participants in the rate-making process. With the resource savings that the ARP is expected to produce, Delta asserts that it could better focus its attention on improving its operations and preparing for a more competitive marketplace. Delta suggests that the proposed ARP would also benefit the Commission by releasing Commission resources from rate-making proceedings to focus upon other matters.

The AG opposes the proposed ARP. He argues that Delta's proposal represents a movement away from setting rates in a manner that ensures that only costs that are properly recovered from ratepayers are included in revenue requirements.[85] He argues that the proposal is inconsistent with "generally accepted rate-making principles." The ARP, he further argues, contains fewer incentives for cost controls and reductions and operational and financial improvements than does traditional regulation.[86]

The AG rejects Delta's contention that the proposed ARP is similar to the performance-based rate-making measures recently incorporated in several gas supply clauses. He notes that formula rates addressing rate of return as an element of the formula have been used only where the legislature has specifically instructed the

[85] Case No. 99-046, Direct Testimony of Thomas S. Catlin at 6.

[86] Case No. 99-046, Direct Testimony of Robert J. Henkes at 11.

Commission to impose a specific type of rate-making. While fuel adjustment clauses and gas supply clauses use a formula rate, fuel cost, unlike Delta's non-gas operating expenses and return, is a highly variable and volatile cost. Moreover, the performance-based mechanisms that the Commission has approved allow utility gains only to the extent that they surpass difficult benchmarks. Delta's proposal, he asserts, would allow the Company added gains without significant improvements in performance.

The AG also asserts that the ARP is open to gaming through under-budgeted income and/or over-budgeted costs. It has the strong potential of allowing Delta to earn in the upper limits of its permitted ROE range. The AG points to evidence that Delta's operating budgets have consistently been more pessimistic than actual results.

The AG further argues that the cost control mechanisms within the ARP are illusory and will not provide any incentive to control costs or improve performance. As Delta's historic O&M costs have increased at a rate less than inflation, he argues, Delta's proposed use of the CPI-U is not an appropriate factor to use in this instance. He notes that, given Delta's current equity ratio, the 60 percent limitation is, for the foreseeable future, of little, if any, value. The AG further notes that Delta's proposal does not include a provision to make common rate-making adjustments. He concludes that, although the ARP is modeled on the Alagasco RSE Plan, it provides few benefits to ratepayers.

Based upon our review of the evidence of record, the Commission finds the proposed ARP is not in the public interest and should not be approved. We are particularly concerned that Delta investigated few ARPs and focused its attention almost exclusively upon the Alagasco RSE Plan. Moreover, Delta's ARP lacks meaningful cost containment and performance-based incentives to encourage improved utility performance. The plan focuses primarily on guaranteeing that Delta earns its authorized return on common equity.

We find little evidence to suggest that the proposed ARP will reduce Delta's regulatory burdens, free scarce regulatory resources, or reduce the adversarial nature of rate-making proceedings. The ARP's process would merely replace existing rate-making procedures with extensive reporting and auditing requirements and shift existing regulatory burdens from the utility to the Commission.

The Commission further finds the "performance-based cost controls" incorporated into Delta's plan provide few incentives to improve its operations or to control/reduce its costs. The performance-based cost control that uses the Company's "Indexed O&M Expenses" as a benchmark is not challenging and represents little improvement over traditional regulation. The Commission believes that, for a performance-based mechanism to have real meaning, it must require the utility to improve its current performance through either improved customer service or decreased costs before shareholders receive greater returns.

We further find that the proposed ARP is subject to possible manipulation. It encourages the utility to under-budget revenues and to over-budget costs. This incentive is inherent in the plan since the Company is only allowed to recover income sufficient to bring earnings back to the low end of the approved ROE range. On the other hand, if the Company over-earns, it is allowed to retain all income up to the upper end of the established ROE range.

We further find that, given the Company's current level of equity capital, the proposed 60 percent cap on equity capital included in the calculation of the AAC is not a meaningful performance-based control. The Commission remains unconvinced that such a measure would be of any value as a true performance-based control during the proposed three-year experimental period.

A sound ARP should focus on elements under a utility's control. The weather is the most significant cause of differences between budgeted earnings of a natural gas utility for a given year and actual achieved earnings.[87] The Commission is unconvinced that, absent the impact of weather, the proposed ARP will result in significant improvements in Delta's financial condition or its operating performance. To the extent that regulatory action is needed to assist Delta in improving its present condition, we have by this Order authorized the use of a WNA clause in this proceeding.

Despite our decision on this proposal, we remain convinced that properly constructed alternative rate mechanisms have substantial merit in today's changing regulatory environment. We encourage Delta to continue to explore alternative regulatory processes and to expand the present scope of its search to make in-depth comparisons of the many alternative mechanisms presently in use. Such analysis will provide the utility with the best opportunity to develop a mechanism uniquely suitable for its particular needs and circumstances.

[87] Case No. 99-046, Direct Testimony of Thomas S. Catlin at 16.

## SUMMARY

Having considered the evidence of record and being otherwise sufficiently advised, the Commission finds that:

1. The rates in Appendix B are fair, just, and reasonable rates for Delta and will produce gross annual revenues as found reasonable herein.

2. Delta's proposed rates would produce revenue in excess of that found reasonable herein and should be denied.

3. The rate of return granted herein is fair, just, and reasonable, and will provide for the financial obligations of Delta with a reasonable amount remaining for equity growth.

4. Delta's proposed WNA is reasonable and should be approved on a trial basis.

5. Delta's proposed ARP should be denied.

IT IS THEREFORE ORDERED that:

1. The rates in Appendix B are approved for service rendered by Delta on and after January 1, 2000.

2. Delta's proposed rates are denied.

3. Effective January 1, 2000, Delta's proposed WNA is approved for gas service provided for the remainder of the current heating season and for the 2000-2001 and 2001-2002 heating seasons. "Heating season" shall mean the period from December 1 through April 30.

4. After the end of each heating season, but no later than June 30 of each year, Delta shall file an annual report on the WNA. These reports shall contain the information listed in Appendix C to this Order and shall include both monthly data and totals for the heating season for residential and commercial customers affected by the WNA.

5. If at the conclusion of the 2001-2002 heating season Delta wishes to extend the use of the WNA for a definite period or to permanently implement the WNA, it shall, no later than June 30, 2002, formally apply to the Commission for such extension or authority to permanently implement the WNA.

6. Delta's application to implement an ARP is denied.

7. Within 30 days from the date of this Order, Delta shall file with this Commission revised tariff sheets setting out the rates and charges approved herein.

Done at Frankfort, Kentucky, this 27th day of December, 1999.

By the Commission

ATTEST:

Helen C. Helton

Executive Director

# APPENDIX A

## APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 99-176 DATED 12/27/99

| Component of Capitalization | Capitalization Per Books: Dec 31, 1998 | Capitalization Per Books: Ratios | Adjustments: Subsidiaries | Adjustments: Canada Mountain | Recommended Capital Structure |
|---|---|---|---|---|---|
| Common Equity | $ 28,351,812 | 30.95526% | $ (1,280,279) | $ 831,892 | $ 27,903,425 |
| Long-Term Debt | 54,207,845 | 59.18555% | 0 | 1,590,553 | 55,798,398 |
| Short-Term Debt | 9,030,000 | 9.85919% | 0 | 264,956 | 9,294,956 |
| Total Capitalization | $ 91,589,657 | 100.00000% | $ (1,280,279) | $ 2,687,401 | $ 92,996,779 |

| | |
|---|---|
| Canada Mountain Investment 7/31/99 | $ 16,268,317 |
| Less: Canada Mountain Investment 12/31/98 | 13,580,916 |
| Capitalization Adjustment - Canada Mountain | $ 2,687,401 |

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 99-176 DATED 12/27/99

The following rates and charges are prescribed for service rendered on and after January 1, 2000 for the customers in the area served by Delta Natural Gas Company, Inc. These rates and charges include the gas cost adjustment approved in Case No. 97-066-H.

RATE SCHEDULES

AVAILABILITY

Available for general use by residential, commercial, and industrial customers.

RATES

| | Base Rate | plus | Gas Cost Recovery Rate | equals | Total | |
|---|---|---|---|---|---|---|
| **Residential** | | | | | | |
| Customer Charge | | | | | $ 8.00 | |
| All MCF | $3.6224 | | $3.2071 | | 6.8295 | Per MCF |
| **Small Non-Residential** | | | | | | |
| **General Service** | | | | | | |
| Customer Charge | | | | | $17.00 | |
| First 200 MCF Per Month | $3.6224 | | $3.2071 | | 6.8295 | |
| Next 800 MCF Per Month | 2.4000 | | 3.2071 | | 5.6071 | |
| Over 1000 MCF Per Month | 2.0495 | | 3.2071 | | 5.2566 | |

## Large Non-Residential

### General Service

| | Base Rate | plus | Gas Cost Recovery Rate | equals | Total |
|---|---|---|---|---|---|
| Customer Charge | | | | | $50.00 |
| First 200 MCF Per Month | $3.6224 | | $3.2071 | | $6.2952 |
| Next 800 MCF Per Month | 2.0063 | | 3.2071 | | 5.2134 |
| Next 4000 MCF Per Month | 1.3190 | | 3.2071 | | 4.5261 |
| Next 5000 MCF Per Month | 0.9190 | | 3.2071 | | 4.1261 |
| Over 10,000 MCF Per Month | 0.7190 | | 3.2071 | | 3.9261 |

### Interruptible Service

| | | | |
|---|---|---|---|
| Customer Charge | | | $250.00 |
| First 1000 MCF Per Month | $1.6000 | $3.2071 | $4.8071 |
| Next 4000 MCF Per Month | 1.2000 | 3.2071 | 4.4071 |
| Next 5000 MCF Per Month | 0.8000 | 3.2071 | 4.0071 |
| Over 10,000 MCF Per Month | 0.6000 | 3.2071 | 3.8071 |

# APPENDIX C

## APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 99-176 DATED 12/27/99

Delta Natural Gas Company, Inc. shall include the following financial and statistical data in its Annual Report to the Commission on the Weather Normalization Adjustment (WNA) pilot program:

1. Number Of WNA Customers (By Class)
2. Amount Of WNA Revenue (By Class)
3. Mcf Volume Adjustment Resulting From WNA (By Class)
4. Average WNA Revenue Per Customer (By Class)
5. Amount Of WNA Revenue (Total Company)
6. Mcf Volume Adjustment Resulting From WNA (Total Company)
7. WNA Impact On Earnings For Reporting Period
8. Actual Number Of Heating Degree Days
9. Normal Number Of Heating Degree Days
10. Variation Of Actual Temperatures From Normal Temperatures (%)
11. Number Of Customer Inquiries About WNA Program
12. Number Of Customer Complaints About WNA Program