BPA FEDERAL REGISTER NOTICES

PUBLIC MEETING

SUBSCRIPTION POWER SALES AND STANDARDS FOR SERVICE

SUBSCRIPTION POWER SALES TO CUSTOMERS

CUSTOMERS' SALES OF FIRM RESOURCES

DATE TAKEN: May 27, 1999

TIME: 10:00 a.m.

PLACE: Cavanaugh's Inn at the Park
303 W. North River Drive
Spokane, Washington

COURT REPORTER: Teresa L. Rider RPR, CSR

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ALLEN BURNS: My name is Allen Burns. I'm the Vice-president of Power Marketing at Bonneville's Power Business Line, a new position I've had for a couple of weeks. I appreciate the opportunity to get up and listen to peoples' comments and concerns today. It looks like we might have suffered a little bit from the nice weather. The good news is that probably means we'll have plenty of opportunity for people to share their comments and concerns on the two issues today.

We have two things we're going to be talking about, I'm not going to get into it in detail, because Steve Oliver will give you a little bit of the context and background and some of the reasons why we're doing some of the things we're doing. We're going to be talking in the morning about standards of service for becoming a customer of Bonneville's. Then in the afternoon we're going to talk about the net requirements policy, which has to do if you own resources, how much load can you place on Bonneville, and how you manage those resources. A couple of important issues that we have to talk about.

I was thinking that maybe what I would suggest is we have a couple of objectives for the discussion today and maybe a couple of ground rules that will help us get through it. And with a small group that hopefully will be easier than if we had a larger group. One of our first objectives today is to be sure and communicate to you what we're proposing. Right now we just have a proposal, we're not going to be making a decision for a while, so there will be plenty of opportunity to comment. We're interested in making sure you leave today, maybe not necessarily agreeing with what we're proposing, but you know what we're proposing, and some of the rationale of why we're proposing that.

The second objective, and equally and maybe more important, and where we're going to spend most of the time is listening to your comments, where you agree with what we're proposing, where you have concerns with that, why you have those concerns. So we'd like to walk out of here making sure we understand where you're coming from, and know what your issues and concerns are.

So a couple of ground rules, we're not going to try to debate things, we're not making decisions today. So when we get to that point where you understand what we're proposing, we understand your concerns with it, we're probably going to try to move on, we're not going to try to debate endlessly whose position may be right or wrong at this point, but make sure we have a good understanding.

Lastly, we want to make sure everybody has an opportunity to comment on those issues, and with a small group I think that's going to be pretty easy.

So, with that I'll turn it over to Steve Oliver, and he's primarily responsible in managing these and several other issues.

STEVE OLIVER: I want to introduce people on the team, so as you see them sitting around you know how to contact them and talk to them. Like any good public meeting Bonneville has, I think we're equal number of Bonneville people that are here from the outside. I want to introduce Tim Johnson and Tom Miller from our legal office staff. A lot of issues we get into here tend to get back in our legislative mandate, so it's important to have their perspectives and help in terms of questions and clarifications. Fred Rettenmund and David Fitzsimmons are here, and have taken the lead on looking at the eligibility issue, and Larry Kitchen is here and has done sort of the yeoman's work on the net requirements policy. Also Mike Hansen and Patti Sager, if you have questions or issues in terms of how to break through the huge crowd here and get a comment they'll assist you on that and work with you on that.

If you haven't signed in, please do so so we have that. This is a public meeting, and we're trying to record it. If you would please identify yourself when you speak we'd appreciate it.

The agenda today is I'm going to do a little context setting here briefly, and then we're going to go right into the morning we're going to spend as much time as necessary on the eligibility issue and Fred and Dave, Tim and Tom are going to do a brief overview on the standards for service, and then we're going to take clarifying questions, if there's confusion or just anything of that nature on it, and then we're going to go into a pure comment period on it. If you comment during the questions, that's great, we'll note those, but we're trying to break it up in that sort of format.

Then we're going to have a lunch break, and come back, and Larry is going to give a brief overview on net requirements policy, take clarifying questions, and go into a comment period on that and then wrap it up. With a smaller group obviously I think it will be pretty easy to deal with questions along the way. So feel free to break in with this size of a group.

So why are we doing these policies? We really don't do these -- we're interested in doing them. They're fairly complex. Following the passage of the 1981 Regional Power Act, we entered into 20 year contracts with regional preference customers, and those are due to expire. One of the key mandates that they arrived at in the '81 Act was the concept of providing Federal power benefits only for net -- net requirements for northwest customers loads. And net requirements means the difference in customer loads compared to resources, dedicated by the customer to serve those loads.

In the 1981 contracts we had a mechanism called the Firm Resource Exhibit that was used to basically take the Act and implement it. And right now for the first time really in the last 20 years we're taking a look at that, that implementation method, and reworking it and trying to come up with a policy and contract mechanism to complete and follow that mandate. At this time when we're looking at network requirements we're required to determine who is eligible to take Federal power.

A lot of things have happened in the market in the course of the last five years with wholesale market deregulation, and actions by individual states such as Montana in terms of a retail access and deregulation, and so we've had a lot of interest from parties, we've seen new parties in terms of forming new public loads, interest in tribes by forming public utilities and taking power. So we need to address the issue of eligibility at the same time.

Our objectives in this process are first of all to be very clear on how we plan to calculate net requirements as the basis for post-2001 contracts. We also want to define and document standards for eligibility that take Federal power on a preference basis.

Another objective was to depart from our course only to reflect new market conditions or meet needs voiced by regional interests consistent with the law.

A third objective that we had was to make it possible to broadly spread benefits of Federal power within the region. And this includes northwest tribes, public bodies, as well as establishing net requirements for western utilities in the region, to take residential power to residential and farm loads. We also want to allow the utilities the greatest flexibility with marketing their resources and interacting with the market without penalizing other regional customers while they're about their business doing that.

And finally we want to retain low cost resources for regional use, that's a clear objective we have.

So the process we're about right now, then, is that in March we sent out some discussion papers just to initiate a dialogue with the region. We heard that we needed to clarify the very complex issue of net requirements and it, by its nature, just is a complex issue. But we went back in with the Federal Register and tried to clarify where we're heading with that.

We also heard there were mixed concerns about the standard for service eligibility issue. Some parties told us we weren't going far enough in terms of relaxing the standards for service and eligibility, in order to meet the deregulated changing market. Others said we were opening far too wide a door in the changes we were proposing in the policy, and we were going to encourage sham public utility formation, and that would cost existing consumers money.

But we went back and took those considerations and really tried to clarify our policy, by placing them in these Federal Registers, which we published on April 26th, and we have a proposed public comment close for June 11. Subsequent to that time of the public comment period close we're going to write a Record of Decision and taking into account all the comments that are received. If we substantially modify the proposals that we've made, based on the comments, it's likely we will put another sort of a proposed Record of Decision out for comment at that period and do a final, so everybody can look at major modifications that have happened. We're interested in your point of view in terms of this public process and the comment period. Would you like a longer comment period on the public registers before the Record of Decision, or would be it be adequate that subject to significant modification if we came out with a second comment period, if things are modified, but if not, perhaps we proceed to conclusion in terms of the Record of Decision. So if you have comments in those areas procedurally, please feel free to let us know.

Once these policies have been finalized through one of these methods that I was just talking about, they will be used, then, by each of the individual account executives to meet with customers and work with you bilaterally to apply these policies into a contract format for the post-2001 contracts. And I think there will be a lot of ability working with individual account executives to go into great detail on the applications, depending on your circumstance. If you have a lot of resources that you're interested in actively dealing in the market with, those kind of discussions can happen. The individual account executives will then document decisions on scoping of the net requirements and eligibility issues, if there are eligibility issues, and we will proceed forward with contracts on that basis.

At this point just a real rough overview, I mean really it's just this context setting where we're trying to head on standards for service was we were trying to keep our proposal fundamentally consistent with our historic course of conduct, and we've kept six out of the seven fundamental requirements in place. The only standard we really proposed to change that we're talking about, although we've talked about that in other areas, is the obligation to own the distribution system. And we believe that the proposal we've made is relatively conservative. We're interested in your comments on whether that's true from your perspective or not, and Fred Rettenmund will be going into that in more detail.

With regard to net requirements, this is a complex area. And what we tried to do is tried to use the current Firm Resource Exhibit source as a benchmark for this, because of the complexity, because it was, we think, a reasonably good standard that people have understood for the past 20 years. We're proposing to start pretty much with that as a benchmark, and we've made an assumption that after taking a look at all the resources that have been dedicated in the Firm Resource Exhibits as not being available to take Federal power behind those, that all of the resources we take a look at we're going to assume have been exported subject to some criteria we laid out that you would basically provide to us, that would know that that wasn't a resource used for regional use. If you can meet those criteria and requirements, this area of net requirements that would have decremented, can be reinstated and you can preserve your net requirements in that area.

It may sound a little bit harsh in the approach of assuming export, but in the context of deregulated market, where we don't have information on transmission schedules and loads, on the power business side, and we're not interested in finding that, it's going to rely on a showing by the customers on what they intend to do with those resources, how they intend to use them in the region or to export them, et cetera, as to whether or not there's a belief or reliance on their ability to have been used and preserved for regional use. And Larry Kitchen will get into that in a lot more detail in the afternoon. That's our approach.

The last thing I want to cover is the NEPA coverage. There may be some interest on how these policies were covered in terms of environmental requirements, review requirements. On December 21st, BPA issued last year the Power Subscription Strategy Record of Decision that really these policies are really implementation pieces of. And that subscription ROD was considered to be, and reviewed, and was within the scope of our business plan final environmental impact statement that we issued in June of 1995. And in that subscription ROD that I mentioned we did in December we talked about section 5(b) and 9(c), so our view is that these policies have been considered and are covered under that environmental impact statement of our business plan. And if you want more information on that, we can talk about that at some point, I don't know if there are concerns with that, the person that's the contact on that is Cathy Pierce, and we can put you in contact with her.

So with that, what we'd like to do is set up a panel over here that will be Fred Rettenmund, Dave Fitzsimmons, Tim Johnson and Tom Miller, they'll walk through the overview a little bit. We have heard that there may be some interest in paneling, some people may want to panel and make comments, we're going to leave this table for comments, and you can use the speaker or microphone in the middle, and we'll go from there. Are there any questions in terms of process or anything of that nature? If not, thanks.

FRED RETTENMUND: Good morning everybody. Dave and I are account executives in Bonneville's retail hubs and we appreciate, along with Tim, and Tom a chance to be here today.

Steve has done a real good job of doing the setup for standards of service. I won't go through all that's in the Federal Register Notice, hopefully all of you have had a chance to read that or at least look through it. What I'll do is kind of highlight some of the key points in that Federal Register Notice, and get on to the important part of our session here today, that's the comment part of it.

The standards for service that Bonneville has apply both to non-preference entities as well as preference entities. I think that it's fair to say that to date anyway there has been more interest in what the standards for service and eligibility requirements will be for new preference customers, and we'll probably spend a little bit more of our time and more emphasis on that part today than maybe the non-preference part of it. Steve had indicated a number of things going on that kind of lead us to consider our traditional standards of service and assess whether or not that's going to work for the future. I won't go into that.

Kind of the threshold issues when you're looking at standards of service, and technically I don't think it's a standard for service, per se, it's just the eligibility for preference, to be eligible to become a preference customer there's really a basic requirement in the Bonneville Project Act, which is one of our key guiding pieces of legislation, and that is you have to be a public body or you have to be a cooperative to be eligible for preference status. And there are specific kind of definitions of what it takes to be those two kind of entities. In large part what it takes is to be a nonprofit kind of at-cost business enterprise. In addition, the Bonneville Project Act talks about that these entities have to be in the business of selling and distributing Federal power. That's a key kind of concept, distributing Federal power. We'll talk about that more in a little bit. They also have to be given a reasonable time to form and kind of get in the business of their utility operation, including being given a reasonable amount of time to arrange for the financing or other kind of approach to construct or acquire the distribution system of facilities that are necessary and desirable to perform the distribution function.

In the long and short, to date over the last, I guess, 60 years or so, it's been Bonneville's consistent interpretation that to be a preference customer, per the provisions of the Bonneville Project Act, you needed to own, an applicant that was applying for preference status needed to own its distribution system. That's kind of a key backdrop item.

This is the first time that we've ever went out with any kind of broad public involvement public comment period. Traditionally the standards for service has been on a case-by-case basis. If an entity wants to become a preference customer, simply stated they send us a letter describing their situation, and seek an indication from us as to whether they qualify to become a preference customer. So this is a different approach for us to kind of go through this whole process and articulate in a more formal way what our standards for service are.

As you can see on the board over here to the right, which just lists what's already in the Federal Register Notice, there are six standards for service starting with the most basic. Fortunately I've got them written down here, because I can't read that far away, but legally formed is the first one. Own a distribution system and be ready in a reasonable period of time to take service from Bonneville. Have general utility responsibility -- and I'll describe some of these in a little more detail later -- and ability to pay for the services received. Have an adequate utility operations and structure, and also basically be of sufficient size to be able to purchase power at a wholesale, commercial amounts. Of course I think all of you know Bonneville is in the business of selling at wholesale. We don't sell at retail, with one exception, to a certain class of industrial customer, so we need to have the customers generally be of some sufficient size.

I'm not going to walk through all of those, I just kind of would hit on some highlights about two of them, those being the distribution system item, as well as the general utility responsibility. The distribution ownership issue, is sort of the fundamental, and I'm going to lean more heavily here on my colleagues, here, from our office of general counsel in a while. I'm sure when we get into some of the clarifying questions phase of this, but part of our whole legislative structure to Bonneville, of course, and preference sales is to sell to those public bodies and co-ops so that they can fulfill sort of the basic public purposes of selling Bonneville's Federal power.

Well, what are those public purposes? It's widespread use and non-monopolization of Bonneville's power, and basically this yardstick for competition. It's sort of the key backdrops for Bonneville's preference sales, and that would include selling at cost, both the cost of the power, the electrical power that we sell and in turn the cost of distributing the power at retail. Those are kind of key aspects of this whole preference structure, including the distribution part of it, and the distribution ownership by the preference entity would allow those broad public purposes for Federal power to be achieved. I'm sure we'll get comment on some other ways those objectives can be accomplished, but traditionally that's how we've looked at it.

On the other one, general utility responsibility, that essentially boils down to that the Federal power has to be sold on a nondiscriminatory basis, it has to be available for all types of retail customers, should any -- the preference, the potential preference entity would have to basically stand ready to serve any retail customer that came forward and requested service from that entity within the service territory, if you will, of that potential preference customer.

Well, what are we proposing to change? As Steve mentioned, we are only really proposing one change, it's not a leap from where we have been traditionally, it's a rather modest step from where we've been traditionally, and it's to change to basically an ownership type lease arrangement for the distribution facilities. Now, we're making this proposal for a number of reasons, but to me it kind of boils down to three keys, one, it appears to be consistent with DOE policy, and how they've approach this in other situations with power marketing agencies. It may meet the needs of a certain kind of new entities that would like to become preference customers, and I think thirdly and equally important it is still consistent with the statutes that Bonneville has to operate under and is mandated by.

What are the fundamental attributes of this ownership type lease approach? Well, basically the term of the lease would have to be for the life of the distribution facilities that would be leased or at least as long as the term of the power sales contract that this entity wanted to enter into with Bonneville.

Secondly, as part of this whole passing through the cost basis for the Federal power, the potential new preference customer would have to have the right or responsibility for the operation and maintenance of these facilities and have an ability to control the costs of doing that operation and maintenance.

As we said in the Federal Register Notice, the kind of transaction of this ownership type lease arrangement would have to be done at arms length with the owner of the facilities that would be leasing it to the potential new preference customer, and the ability, then, to operate the system would have to be able for this prospective preference customer to be able to do that in an open and competitive process, to select -- either do it themselves or select some other alternative vendor or provider of the operation and maintenance of those facilities. So it kind of boils down to that the lease -- the party, this new potential preference customer has to have the ability to control the distribution costs, if they go this route.

I'm sure we'll get more clarifying questions and other comments on this.

Lastly, we put in the Federal Register Notice, and it is not part of our proposal, but we put in the concept that contractual capacity rights approach, which to me basically boils down to, I think, many of you are familiar with here in the room with when utilities that don't own transmission lines but need to use somebody else's transmission lines, they set up basically a contract with the owner of the transmission lines to basically make sure they've got the use of a certain amount of capacity on those transmission lines. This concept at the distribution level is very similar to that. It would allow the potential new preference customer to basically contract for a certain amount of capacity on the lines that another entity would own. Now, as I indicated, we're not making that proposal. There's some significant legal questions about whether that's doable and workable, but we know we're going to get some comments from some folks that are interested in going that way, so we put it in for discussion purposes.

Even with this last sort of possibility or concept that we've put in for discussion purposes, this potential new preference entity would still need to perform all the other utility functions, they'd need to be able to either -- they need to bill, read meters, set the retail rates, et cetera, so that would all be part of the package that this new entity would be responsible for.

I've run through that real quick, that's kind of what's in the Federal Register Notice, and I think now is the time to turn to the clarifying questions part of it before we get on to the more substantive part, which is the comment opportunity.

BOB CRUMP: The proposed change, is that one that Bonneville has come up with or is that one that's a response to customer or customers who have asked for that change, and if so, who are those customers and what is the nature of that deal?

FRED ROSE: You need to, for the record, indicate who you are.

BOB CRUMP: Bob Crump, Kootenai Electric. The question was whether or not this proposed change was something that Bonneville on their own is proposing or whether this was something that has been received by customers or potential customers, and if so who are those potential customers, and what's the nature of their interest and what are they proposing?

FRED RETTENMUND: This is Bonneville's proposal. It's not -- we have had, and I don't know who -- myself, I don't know who, if anybody else has suggested we go this way. This is our proposal. I'm sure we'll get comments throughout the course of this effort that some people will think, yeah, maybe this is okay or maybe not. This is our proposal. I haven't seen any letter that has come in that says Bonneville, you ought to put this in your Federal Register Notice, nor have I heard any direct communication that way.

Any other clarifying questions?

BILL DRUMMOND: My name is Bill Drummond. I'm manager of Western Montana G & T. I was just curious, the 37 Project Act requires Bonneville to give customers time to be able to acquire the distribution system to construct the necessary desirable facilities, construct or acquire. What is your thinking with respect to the subscription process and how long you would be willing to hold power available waiting for a customer to construct or acquire distribution facilities? Basically I'm kind of asking how you see the standards of service that you come up with working in conjunction with the subscription process, and particularly the timing of the process knowing that it's to run 120 days after the rate case closes?

FRED RETTENMUND: Well, Bill's kind of taken off on part of the answer, although I didn't bring it up, our subscription strategy that Steve mentioned that we published in December of last year indicates that a potential new preference customer would have to form and have to have -- be able to sign a power sales contract with us within 120 days after we complete our rate case. And while we don't know exactly -- right now -- when the rate case will start, we certainly don't know when it will end, let's just -- maybe it will end January of next year, if it starts here pretty soon, so the 120 days would run us to about this time next year. So, I think, Bill, your point is what we've described is about a window of a year to get in position to sign a power sales contract. We've heard that that's a pretty challenging standard limited period of time for somebody to do that. We are considering if there is a way we can be a little more flexible on that, and I would assume part of this process, when there are comments that come in for the standards of service, we'll not only get comments on the standards themselves but are we allowing a reasonable period of time to achieve those standards and still participate in the next round of contracts. I don't know if that answers your question.

BILL DRUMMOND: You haven't established a time frame really yet.

FRED RETTENMUND: We have, per the subscription strategy we have indicated you need to form and sign a power sales contract within the 120 days after the rate case ends. I'm not saying there isn't -- we are aware that there's need, potentially, for some flexibility on that, but we haven't made any, to my knowledge, any final decisions that we can extend that. I think --

STEVE OLIVER: We have not proposed to hold any power past that point.

LARRY KITCHEN: The other side is you can also sign up later, there's no limitation if a new preference customer forms to sign later.

FRED RETTENMUND: I think there is not a one-time opportunity to sign up and become a preference customer. There is potentially a rate impact by not signing up within the 120 day -- by the end of the 120 day. The long and short of it is if all of the inventory is gone by the end of the 120-day period, we have an obligation to meet the loads of a new preference customer. We've put in the subscription strategy that if we're basically out of inventory and we have to go buy, then that new preference customer may face a higher targeted adjustment rate, I believe we call it.

DANA TOULSON: Dana Toulson, Tacoma Power. I have clarification of a term. You said it would be for the life of the assets or the life of a BPA power sales contract. Could that be as small as five years? And if so, why the second eligibility, why not just the life of the assets, why did you add the term to the Bonneville contract on to the standard?

FRED RETTENMUND: Others are free to jump in here, my answer to that question is it could be as short as five, quite frankly I think it could potentially be as short as three, because we have put in the subscription strategy that it is possible for a customer to sign up for preference power for a three year term. To me the basic logic is if they're going to get the benefits of the Federal power for X period of time, let's say five years. Part of the whole construct here is they have to have the ability to meet the standards for service and pass through the benefits for that same period of time. So it's just making the availability of the PF power, the low cost power, and the ability to form the other part of that chain, the distribution function, we've got to be in sync. I don't know if somebody else wants to take a shot at expanding on that, but that would be my answer to that.

DANA TOULSON: That was my question of clarification. I was just wondering if a three year lease would ever qualify as an ownership type lease, according to the IRS?

FRED RETTENMUND: That I could not answer, I won't try. But if there's a comment you'd like to make about the duration, we certainly need to have that provided.

BOB CRUMP: Your standards of service, I'm assuming, at least from the nature of discussions would be applied to prospectively to new customers, and would not be -- Bonneville hasn't taken the initiative to attempt to apply those to existing customers, is that true?

FRED RETTENMUND: Well, I think we say here in the Federal Register Notice that we'd be applying these to potential new preference customers. It's my understanding that the existing preference customers, by the very fact that they already have an existing contract with us have at one time or another met the standards for service and unless there's a significant change that they sold off all their distribution facilities or something, they're already eligible and will continue to be eligible to buy on a preference basis.

BOB CRUMP: I guess I asked the question because I'm still trying to explore why it is that you're proposing to make a change. Internally if you brainstorm that gee, it would be good to make this change, we think it's timely that we do this, I guess that's one logic, line of logic, another could be, well, gee, the world is changing, the utility business is changing, perhaps we need to recognize that there will be new types of arrangements out there and make this change so that ostensibly you can then open up new opportunities for you which raises questions in my mind about how far can you spread the benefits to Bonneville.

DAVE FITZSIMMONS: I think if you look at -- go back to one of the other original reasons we're doing this, to finally get the standards of service down on paper, because we are getting a lot of inquiries, new interest in forming new publics. And rather than continuing to do it on a case-by-case basis, if we get them down on paper, so as you enter into that process you've got to ask yourself, gee, are things different than they were in the years past and if so, should we adjust to modernize what those standards are? And as Fred mentioned it does bring it more in line with what current DOE standards are.

BOB CRUMP: Have you analyzed in any way what the prospective effects of that might be?

FRED RETTENMUND: In terms of the potential number of new eligible preference customers? Not in any kind of rigorous way. We probably all kind of have our intuitive sense of what that would be, but I don't think we've done a rigorous analysis of that.

Any more clarifying questions? Well, I know we didn't do that good of a job of explaining it.

I guess we'll turn to the comment opportunity, if there are -- that doesn't mean -- I don't think we have to be so formal that we couldn't take some clarifying questions as we went through this. But I think we should turn to the comment portion of the meeting now. I don't have the list of who are the commentors. Just because you didn't sign up doesn't mean you can't comment, either.

I'm disappointed, we let the lawyers off easy, here.

Tom Schneider. Tom from Missoula.

TOM SCHNEIDER: Thanks, I am Tom Schneider. I'm a consultant for a number of public entities and aggregators in Montana. And my comments today are my own, although I intend to prepare written comments by the deadline to submit official comments on behalf of the City of Missoula. The City of Missoula knows I'm here to participate as active as I can today on their behalf.

Let me just set the groundwork a little bit in terms of the activities in Montana and then proceed to how inconsistent I think these proposed standards are with the emerging competitive market, both at the wholesale level and at the retail level.

In 1997 Montana passed a Restructuring Act, which paralleled in many respects other state actions throughout the country, but the crux of it is that supply, that competitive product was open, the regulated utilities in Montana were required to provide equal access, open service on their transmission and distribution facilities to the extent the state had regulation, and of course 888 had already moved that way on the wholesale side. So the competitive power supply market was opened and the ability for retail customers, either individually or collectively in aggregate groups, became an opportunity for the first time. And under those auspices first the large industrial customers had the opportunity a year ago beginning July 1st to enter the competitive supply market in this open access environment. They have substantially done that. The large industrial customers in Montana substantially moved to competitive supplies and are acquiring those supplies over the open access transmission, pursuant to tariffs, and over the open access distribution, again, pursuant to state regulatory tariffs. So the regulatory framework is in place, then, to implement national policy on opening the supply market.

The beauty of, and the rationale for, open access common carrier type approach is to access the competitive supply in as even-handed a way as possible over monopoly facilities.

The trends in Montana, then, for the first time are to try and get as many economies of scale as possible for smaller loads, so that it is not just the large industrials that get the benefit of supply competition, but also other retail customers, and in the largest case to date the League of Cities and Towns represented 23 cities and towns and went to the marketplace a couple of times and did, in fact, aggregate about 160 municipal loads and are acquiring competitive supplies, again, over those monopoly facilities. The Montana School Board Association is about to issue an RFP for an additional 300 school district loads in 60 some school districts in Montana, almost 70 school districts. Again, widely distributed activity under aggregated type purchasing arrangements. That supply again will come over those regulated monopoly facilities.

To switch, then, directly to the standards -- oh, and the other activity in Montana has been for the first time an interest in the formation of public entities in addition to the existing rural electric cooperatives. There are about 26 co-ops in Montana formed in the traditional manner over the last 60 or 70 years.

The advent of the restructuring law has allowed the formation, for the first time, of municipal utilities in Montana. And about a year ago the City of Helena, state capital, which is east of the Divide, formed a municipal utility. Again, to position itself to represent its constituents, its residential and commercial customers within its jurisdiction to provide electric power supply service in the competitive market. Again, pursuant to regulated tariffs over existing distribution facilities of the Montana Power Company.

The City of Missoula is just now publishing, and Missoula is west of the Divide, is just now publishing its ordinances to form a public utility very much along the lines of Helena, but is specifically signed to pursue as aggressively as it can any opportunities to avail itself of preference status, just as other municipal and public entities have. It is a duly constituted elected body acting as it does with other utility services, sewer, water, garbage and so forth. It has a lot of experience in that area. Obviously it wants to qualify for preference power in this competitive market under the Real World Public Policy Initiative of open access to competitive supplies.

The requirement of either owning and operating distribution facilities to qualify as a public entity to spread public power benefits to residential consumers seems to me -- or to consumers within its territory, seems to me to turn the whole open access economic and policy basis on its head. What it requires, then, is a contentious, historic requirement to condemn facilities, to acquire -- or to construct duplicate facilities. How ludicrous can that be in an environment, at the national and state level, that's encouraging the use of existing facilities in an open access common carrier type role?

The requirement to operate and own or acquire a long-term lease of facilities and to meter -- own meters and read meters has nothing to do with the distribution of power supply benefits within a region. It simply is not a requirement in order to spread benefits.

The 1999 legislature in Montana, knowing that Bonneville was proposing these kinds of standards of service, did a couple of things: They allowed the formation of a small buyers co-op that had at least as one public purpose or objective the ability to enter such leases, at least as a -- to give some legal basis for trying to qualify under this standard Bonneville proposes. They also allowed formation of municipal utilities and gave both the ability and the requirement to provide default service, which is the obligation to serve requirement. That makes sense from my standpoint, that whatever public entity qualify not be a sham, but rather have real world supply responsibility and real world qualification as a duly constituted public entity.

So the Montana Public Service Commission, then, will have the requirement to establish default provider status rules. There will be an application process and whether it is the incumbent Montana Power Utility

Distribution System that ends up with that responsibility or a small buyer cooperative or a municipal utility public entity, there are vehicles to do that, and the Commission is going to have to decide whether or not -- what best serves the public. And the City of Missoula, of course, wants the ability to step into that role to serve its citizens, just as the cooperatives and the municipal public utilities in the Northwest have for a long time.

The contracts face a cliff in 2001. No one can rely on those contracts in this new environment. We are in a new competitive environment and it seems to me that the policies of Bonneville ought to reflect those kinds of realities.

So I would sure urge that the requirement related to ownership and long-term lease type arrangements are, in fact, -- the movement to long-term lease arrangement is in fact a real baby step. What it will do in reality, I think, is end up with a stillborn situation in Montana, where new public entities are forced into a noneconomic, duplicative type arrangement to condemn and go through those kinds of procedures, which really have not been done in Montana, in lieu of a regulated tariff, open access environment. Why, from a public policy point of view, would one of the key players in the region seeking to spread public benefits in the region want to force that kind of a result? I would urge you to reconsider.

We will be submitting comments, written comments, and I don't know if we're going to play the game in Portland or not, but thanks for the chance to be here.

FRED RETTENMUND: Thank you, Tom.

Bill, I think you're up next.

BILL DRUMMOND: My name is Bill Drummond. I'm the manager of Western Montana G & T in Missoula. Like Tom, my comments are in draft form, really. They are my own, I have not had an opportunity to submit them to my board, so I can't present them as an official G & T position, but they will be what I'm submitting to them. I'm going to paraphrase a lot of what I'll be submitting in written form so as to save some time. But I do want to say at the outset that we commend Bonneville for acknowledging the significant changes that are sweeping the electric utility industry, and it's a difficult task to try to update laws that have been in place for over 60 years and bring them -- make them relevant to today's circumstances. And that's exactly the task you've got in trying to deal with the 1937 Project Act and subsequent legislation, and still try to develop the new Standards of Service.

While Bonneville's made a good effort to modify these standards, the proposal does not go far enough, in our opinion, to accommodate these industry changes. Western Montana G & T recommends that the proposal be modified to acknowledge the unique circumstances faced by consumers in states that have already adopted utility restructuring legislation. In particular, regional preference entities in states that have distribution system open access requirements, Public Service Commission regulation of distribution costs and that have a utility obligation to serve must be allowed to purchase preference power from Bonneville. In other words, the Standards of Service need to be changed to comport with the changes that are occurring in the electric utility industry. And we support the capacity rights concept that's included in the last part of the Federal Register Notice.

Let me touch upon three elements of the Standards of Service. First, the distribution function. There's several reasons why Western Montana G & T believes that Bonneville's requirement for distribution system ownership should be modified beyond what is already being proposed in the ownership type lease. First, the 1937 Project Act does not require ownership of distribution assets as a condition of purchasing preference power. The relevant section of the Project Act is section 4(d), and if you read that section it basically requires Bonneville to give the preference entity sufficient time to be able to construct or in order to get the financing necessary to "construct or acquire the necessary and desirable electric distribution facilities." As this section clearly states, Bonneville is to give -- basically in the case of a state that's already opened its utility industry to retail competition, it is required that distribution facilities be treated as a common carrier. Ownership of distribution facilities is not necessary to allow the benefits of Federal power to flow through to the retail customer.

Second, Bonneville's proposed position contravenes the vision of the electric utility industries that's included in the Administration's recent restructuring proposal. The Administration's proposal endorses exactly the sort of retail open access that Montana has already adopted. And it's ironic to us that Bonneville's proposal would actually punish states that follow the Administration's lead on restructuring by making the customers of those states potentially ineligible for preference power.

Third, the logic that does not obligate ownership of transmission facilities in order to obtain preference power is equally applicable to distribution facilities. Ownership of transmission facilities is not a necessary condition to obtain preference power, because the cost of the transmission service is regulated by the Federal

Deregulatory Commission, while -- with open access and continued FERC regulation of transmission costs the benefits of cost-based Federal power can flow directly through to the preference entity without fear that those benefits would be captured by the transmission owner as monopoly rents. In Montana, where open access of the distribution system is required by state law, and where the cost of the distribution system will continue to be regulated by the Montana Public Service Commission, ownership of the distribution system is not necessary to guarantee that the benefits end up with the final consumer.

Bonneville stated in an enclosure to its May 14th, 1999, letter to Mick Robinson, who is the senior policy advisor to Montana Governor Roscoe, that "the ability to control costs is an important aspect of the customer's ability to demonstrate that the benefits of cost-based Federal power will be passed on to the retail consumer." Again, with Public Service Commission regulation of distribution system costs, we don't believe that ownership is necessary.

Finally, it's my understanding that the Western Area Power Administration's recent proposal to sell power to Native American Tribes explicitly states that ownership of poles and wires is not a necessary condition for their receiving preference power. As part of its energy planning and management process WAPA specifically rejected the previously held condition that eligible tribes own distribution assets in order to receive an allocation of preference power. WAPA is now negotiating the delivery of Federal power to these tribes, even though the tribes do not own any distribution assets.

What distinguishes Bonneville's requirement for distribution asset ownership as a condition of preference service to tribes and preference customers from WAPA's condition lacks in that constraint is unclear.

Let me turn to the obligation to serve. The obligation to serve -- I'll shorten this -- in essence, in the State of Montana as Tom described, the Public Service Commission will determine who is the default supplier, who carries the obligation to serve those customers that either don't have a choice or have not elected an alternative supplier. And that default supplier will be obligated to serve all customers within the territory designated by the Public Service Commission for customers that are less than 100 kilowatts in size.

Bonneville lists as one of its requirements in the Standards of Service, that the preference power purchaser must have the general utility obligation to serve. In Bonneville's words, this assures that Federal power will be sold by the applicant in a nondiscriminatory manner to the benefit of the general public, and especially -- in Montana when a supplier obtains default supplier status, it agrees to shoulder the utility obligation to serve. That default supplier obligation extends to all customers of the appropriate size within the territory designated by the Montana PSC.

In the aforementioned letter to Mick Robinson of May 14th, Bonneville also notes that its utility -- this is Bonneville's utility obligation to serve requirement -- contains no customer size restriction, as does the Montana legislation. This concern that Bonneville raises is unfounded for two reasons, first, as noted in Bonneville's letter, this is a quote, "Bonneville has traditionally required that a customer serving retail load must have a 'utility responsibility to serve.' this means that any retail consumer may request and obtain service limited only by service area or franchise restriction." Basically in the franchise restriction is what I want to emphasize. The Montana legislation authorizing default supplier status specifically places a restriction on how large a customer can be in order to obtain default supplier status. And so in our view the franchise restriction is contained in the state law, so that should not be a problem.

Second, if you look at section 4(a) of the Bonneville Project Act, it talks about ensuring the benefits of facilities, basically Bonneville's facilities, should be operated for the benefit of the general public and particularly of domestic and rural consumers. Domestic and rural consumers are exactly the customers that would be served by the default supplier envisioned in the recent Montana legislation. It's difficult to understand how a preference utility explicitly designed to serve domestic and rural customers would therefore be even eligible to receive preference power, because it was not legally able to serve large commercial and industrial customers.

Last standard of service I just want to mention briefly, is the operations and structure standard. This portion of Bonneville's proposed Standards of Service needs to be modified to acknowledge that the issue is whether "the applicant has the ability to fulfill its responsibilities and duties under a power sales contract." Although the proposed standard explains that Bonneville will examine the applicant's ability to perform metering, billing, perform operations, maintenance, et cetera. The real question is whether it's able to meet its contractual obligations to Bonneville.

For example, under Montana's restructuring legislation, the metering function is to remain the distribution facility's responsibility. The important element for the commodity provider is whether it will be able to access the metering data to be able to send out bills, receive funds, et cetera. Bonneville's proposal should be clarified to distinguish that the agency is really only interested in whether the purchasing utility can fulfill its contractual obligations, not whether it owns the meter.

Again, I will be submitting final comments later on.

FRED RETTENMUND: Bill, if you would allow me, can I ask one clarifying question from this side? I thought I understood you to say in your initial remarks for those states that have already passed basically retail access legislation. Do you have the comment about prospective if we get another state in the Northwest passing a law next year, what would be your sort of view on that situation?

BILL DRUMMOND: I think the standards would have to apply to them, as well. You can't be changing your Standards of Service.

FRED RETTENMUND: You'd open it up for them, as well?

BILL DRUMMOND: It's hard for me to forecast what they might do and how their open access requirements might eventually come out.

FRED RETTENMUND: I wondered if you were grandfathering in only those that have passed it today?

BILL DRUMMOND: That would be okay --

FRED RETTENMUND: Thanks, Bill.

Margie?

MARGIE SCHAFF: Thank you. I'm Margie Schaff and I'm with the Affiliated Tribes of Northwest Indians. The Affiliated Tribes applaud the application of preference status to Indian Tribal utilities that meet the Standards of Service established by Bonneville. That's a historic decision by the Administrator and it's much appreciated by many tribal entities. The Tribes recognize the importance of reasonably priced, reliable and consistent electrical service to their reservations. Power is a basis of infrastructure that is a cornerstone to economic development. And as tribes move into the new millennium, we'll further our cultural and economic development by insuring access to basic community services and by managing these services in ways that meet the needs of the reservation, the tribal culture and the region. We appreciate the opportunity to participate here as preference customers in this discussion, and to provide our comments on the proposal.

The wealth of tribes has always been tied to the rivers and other natural resources and access to those resources is of utmost importance. Our economies and those natural resources have changed over time, but basic relationships, rights, obligations, promises, and the different treaties between the various tribes and the government remain the same.

Tribes have a different political status to Bonneville than do other customers, due to the tribal trust responsibility, and due to the government-to-government status established in executive orders and policies.

Many treaties guarantee rights which are related to and affected by the operations of the river systems and by the sale of power. Federal actions affecting the river systems over the past 60 years have not lived up to the obligations of the trust responsibility. Even though the responsibilities have been consistently espoused by Federal courts since 1831, and the trust responsibility derives from the Federal government's original, purposeful destruction of the tribal livelihoods and economies. The Supreme Court in 1941 in the case of Seminole Nation vs. US, stated that the Federal government has charged itself with moral obligations of the highest responsibility and trust. Its conduct as disclosed in the acts of those who represent it in dealing with the Indians should therefore be judged by the most exacting fiduciary standards. The same trust principles that govern private fiduciaries, also describe the scope of the Federal government's responsibilities to the tribes. These include preserving and protecting trust property, including a trust duty of protection when off reservation actions affect tribal rights. Second, informing the beneficiary of the condition of trust resources and third, acting fairly, justly and honestly in the utmost good faith and with sound judgment and prudence.

The court's commonly reiterated that the trust imposes on the United States an overriding duty to deal fairly with Indians wherever located. Laws passed and treaties signed are to be broadly construed to protect tribal interests. While history has not always exemplified the Federal trust responsibility, the Affiliated Tribes of Northwest Indians has been pleased with the current, continued government-to-government consultation between Bonneville's Administrator and the tribal councils. And the Administrator's willingness to listen to and consider tribal concerns and to exercise her trust responsibility. We therefore make the following comments to the proposal before us: First, tribal utilities formed under tribal laws to service reservation lands should be interpreted to be either public bodies under section 3 of the Bonneville Project Act or cooperatives. Limiting tribal utilities to the status of cooperatives limits our ability to use tribal tax exempt bonds and other financing forms stemming from a governmental status. It also insults the government-to-government status between the tribes and Bonneville.

Importantly, some elements of sovereignty inherent in tribal governmental bodies may be lost by creating cooperatives. Also cooperatives are a new form of entity that is not known in the financial world, this adds risk and therefore percentage points and cost to our ability to obtain financing.

Tribal governmental bodies have standard financial arrangements used to raise capital for infrastructure projects. While section 3 of the Bonneville Project Act does not specifically mention Indian tribes, along with "states, public power districts, counties, municipalities, including agencies or subdivisions thereof, numerous other statutes that do not mention tribes, have been interpreted to include them to further the intentions of the laws. Obligations under Indian law, and there are numerous cases, and the Federal trust responsibility, allow the Administrator to consider a tribal utility to be "a public body," preference entity. Regional tribal loads equal less than 50 megawatts, however, no tribe will likely form a utility if they are not able to obtain reasonable financing. Due to this minor glitch in reading statutes, they will not be able to form.

Our second issue is timing. We support the opportunity of tribal utilities to subscribe to lowest cost Bonneville power throughout the 20-year period under flexible rules allowing a reasonable time to determine engineering, economic and managerial feasibility for utility establishment and to establish boards and obtain financing. Cities and counties have historically and traditionally been eligible preference customers. We have known of this opportunity for a very short time, and still do not know all of the requirements necessary to form their utility. Upon clarification of the Standards of Service we will still need to negotiate with suppliers and current service providers. The current proposal does not allow us time to accomplish that. We request an extension of this time. Perhaps tribes and other new customers could also be provided the right to subscribe at the lowest cost to power becoming available as other customers' contracts expire throughout the 20-year period of time.

The Affiliated Tribes also support Bonneville's approval of ownership type lease arrangement for power distribution to power customers. We further support Bonneville's approval of contractual capacity rights for delivery of Bonneville power. These are consistent with DOE policies of open access, and encouraging competition, and the widespread use of Bonneville's power.

The request by some entities that the ownership obligation remain is basically a request by those entities to limit the ability of new entities to become preference entities. If there's truly a policy reason for limiting the number of preference customers, that issue should be addressed directly, and should not be hidden behind an issue of ownership of wires.

With the unbundling of services throughout the utility industry there's no technical or commercial reason to require a utility to own its wires. Leasing or shared capacity keeps costs down by eliminating the need for redundant facilities. As an example, the Fort Mojave Indian tribe in Nevada, which was a former WAPA customer, years ago before the policy changes, has lands interspersed with private lands, and they were required to own facilities by WAPA. They built an entirely redundant distribution system, where next door a nontribal member was served by someone else. The Fort Mojave is still the least expensive electric supplier in the State of Nevada.

The leased capacity rights works beautifully in high voltage transmission systems. The policy of leasing or contracting for delivery services encourages cooperation and community among utilities serving different customers in the same proximity. We also support the Bonneville suggestion of reliance on governing law to determine who will have the obligation to serve and the obligation to own wires should open access laws be passed by either states or tribes, their laws should be considered in Bonneville's decision of who is a preference customer and who has met the standard of service.

We suggest that any lease or contract for use of the wires be for the life of the BPA power supply contract, however, and not for the life of the facilities as suggested by Bonneville in the Federal Register Notice.

The Affiliated Tribes of Northwest Indians look forward to an exciting and cooperative relationship with Bonneville and utility neighbors, and again we appreciate the opportunity to comment and we look forward to a continued positive working relationship.

FRED RETTENMUND: Thank you, Margie. Is there anyone else who didn't sign up who would like to comment at this time? Bob?

BOB CRUMP: Bob Crump. I'm general manager of

Kootenai Electric. And these comments are not only my own, but I'm quite sure that my board would agree, as well.

First of all, I guess my major concern is that in Bonneville's attempts to spread the benefits in the region as far as they possibly can will have the effect of actually spreading themselves too thin, and rendering the benefits practically nil over the long-term. And specifically I guess I'm concerned about post-2006 time period. I'm fairly confident that you can, over the next rate period, come in with rates that are going to be attractive and people will find beneficial. Obviously a lot of these people wouldn't be here saying the things they are, if that wasn't generally accepted, although I still find it ironic if you had done this process a few years ago, you probably wouldn't have heard some of these comments. That's my major concern.

As far as the State of Montana goes, I find that particularly interesting, too, and I guess my easiest way of explaining that is obviously the state wants to have its cake and eat it, too. And I have to question whether or not their faith in the open market and deregulation is as strong as it should be, given they'd like to have access to Bonneville Power.

The two don't seem to me to go together. If they were willing to take the risks when they deregulated, then why do they need Bonneville Power?

My concern also is with new preference customers, and this goes with my first point, as new preference customers or new customers, period, come on the scene, it seems to me that Bonneville needs to have some way to differentiate, and I know there are several proposals out there to do that, to differentiate as far as what would be the priority firm rate that they might pay. Customers who have been on the Bonneville system historically have shouldered the burden, have been there as a good load to Bonneville, ought to continue to get the benefit of that relationship. And I'll probably be submitting more detailed comments, but those are my general ones.

FRED RETTENMUND: Thanks, Bob. Anyone else that would like to comment? We're open for written comment until the 11th of June, and we are going to have another session next week in Portland, so this isn't your only chance. I appreciate it, and I guess we're done, and we'll turn it back over to Steve.

STEVE OLIVER: Thank you. I have sort of a process question, here. It's 11:20. We have a very large convention or a couple of them going on here at the hotel, and there's one restaurant. So we have a couple of -- I think the two options are we could break now and get ahead of the restaurant crowd a little bit, come back and do the overview on net requirements and take comments on it, or we could end up just working through this whole thing right now, and everybody get a very late lunch. So I really would -- I think we're willing to do it either way. And probably the overview that Larry is going to give is maybe a 15 to 20 minute description of the net requirements piece. We'll take clarifying questions and comments on it.

So option A is break now, have sort of an early lunch and get ahead of the crowd or option B is let's just stay and work through this. Option A, can I see sort of a sign of hands, anybody want to break now? People that want to work through it, option B, sign of hands? Looks like we're going to go through it, so everybody sort of gird yourselves.

(Pause in proceedings.)

LARRY KITCHEN: One thing I'd suggest before you sit down, that you have a copy of this one page sheet, at least on the net requirements policy proposal, because I'm going to be speaking from that sheet.

What I'm going to do today is provide a summary description of BPA's proposed policies for determining net requirements, it's under section 5(b) of the Northwest Power Act. In that summary, I'm also going to include adjustments to your net requirements for the export of thermal resources, under section 9(c) of the Northwest Power Act, and adjustments for export of hydro resources under section 3(d) of the Regional Preference Act of 1964.

I will then briefly describe two flow charts that BPA has prepared, showing the application of the proposed policy to your loads and resources. That's this document, right here. I will tell you this basically in draft form, but what we're trying to do here is actually take the principles that were in the Federal Register Notice and show how you would actually apply the facts of the loads and resources of your system using those principles, and give you some idea of the logic, sort of how it would flow.

The chart that we've handed out is really a summary description of the proposal, and it really starts with the basic limitation on purchasing Federal power under the Northwest Power Act. Bonneville's required to sell each customer an amount of power necessary to serve its net requirements. Those net requirements are the customer's total load in the region serving consumers less the resources that the customer is required to dedicate to its load under the Northwest Power Act.

Under the policy, I guess, the first step that Bonneville has proposed that using the current customer resource declarations under their Firm Resource Exhibit as a basis for determining the customer's maximum net requirements, that's really the shaded area in the graph, and that would set the maximum amount of power that any customer could buy from Bonneville under a subscription contract.

We've proposed that the only reason that a customer's net requirements can be changed, due to changes in customer resources, are for the reasons enumerated in the statute, those resources are down in the lower right-hand corner: They're a lost resource or a contract, the resource is retired or obsolete, contract termination by a third party is really a lost contract. The final reason in the statute is removed with the Administrator's consent, and what we're proposing is that we aren't necessarily going to consent to the removal of resources, this is different than the 1981 contract. The 1981 contract we allowed resources to be taken off on seven years notice, and Bonneville would construct resources to replace them. Under the Regional Review and Subscription Policy we're basically trying to sell the existing amount of power from our system and when we use our acquisition authority we would do that in a one-on-one relationship with the customer asking for the additional resources and charge them the costs of the acquisition.

We have proposed one exception to this rule, and that is that we would provide the consent to the addition of a customer renewable resource for a specified period during the term of subscription contract, this is targeted to apply to new renewable resources, and provide an incentive for the development of those resources during the term of subscription contract.

As I'll explain later, use of this exception would subject those resources to the application of statutory rules regarding export of resources. But it does give you an option if you build a new renewable resource and you're unable to sell it in the marketplace of actually taking that renewable and applying it to your load during the contract term and reducing your take or pay obligation to Bonneville.

We have also asked for comment for another potential exception to the rule regarding changes in customer resources, and that's really described on the left-hand side of that chart. And that is if a customer in establishing net requirements is losing load due to retail access, that basically load reduces their net requirements and we've asked for comment on whether we should consent to the removal of customer resources equal to that retail load loss. That would allow a customer to maintain the net requirements they'd established. For example, if you were losing load due to industrial customers exercising retail access choices and going off your system and you had a partial requirements, should you be able to maintain that, your net requirement purchase from Bonneville by removing some of your resources from dedicated to load and then selling those resources consistent with the provisions on exports of resources. And we'd be interested in your comments on that issue.

In addition to the rules regarding how you set up net requirements or what I've described as the maximum net requirements, Bonneville must also look at how a customer uses its other resources. We've proposed in our policy to limit our look to existing thermal resources in the region and a customer's hydroelectric resources, unless that customer specifically takes a new resource and dedicate it to load. In the policy we put in a statement that for new market resources or new resources we consider them built for the market, and we wouldn't apply the export test to them, because we wouldn't assume they've been used to serve a customer's requirement load in the region.

So that's to make the application of these rules simpler for new resources being developed and to focus really in on the existing resources that are there in the region.

In applying these policies, one of the issues we have to face is the functional separation of the power business and the transmission business. The power business no longer has the information on whether a customer exported its non-Federal resources, because we don't see your transmission schedules. So we don't know what you did with the resource.

I guess we also had issues under the existing policies when we were trying to use transmission schedules, we would find customers would sell it to another public agency in the region or another customer in the region and that person would export the resource. So we had issues actually in the implementation of the existing policies on whether we could actually track exports in the region. Since we lacked that information what we proposed is make a presumption if you're not using your resources to serve your load, then you're exporting that resource. And the customer can then come in and decide whether they wish to rebut that presumption by saying, no, we're actually using this resource in this manner and it's not being exported.

This is designed to give the customer the choice, whether they share their commercial information with us, that's not something customers actually like to do is to share what commercial deals they're doing. But if they don't share that information, so we can know whether the resource has been exported they will lose their right to buy Federal power. And they'll have to make the choice, which is more important to them. We've set this up so that this can be done on a resource-by-resource basis. Some arrangements for resources they may be willing to share, others they wouldn't.

STEVE OLIVER: Just quickly, when Larry said lose the right to buy Federal power, it would be for the increment of that resource, not total.

LARRY KITCHEN: It would be resource by resource determination.

In applying these rules under this chart, probably the first step in determining what rules apply is identifying whether the resource is a hydro resource, a thermal resource or a contract purchase from someone else. Different rules apply to hydro and thermal resources. Contract purchases must be characterized as either a hydro resource or a thermal resource, basically existing thermal resource or the purchase of a market resource. That you see really in -- you look at the chart, above the shaded resources, you're actually having to identify which of these three types of resource you have. An example, a contract to purchase a share of Mid-Columbia Hydro would clearly be considered a hydro resource. Whereas a contract to purchase through the broker market a block of power delivered flat, basically around the clock, around the year, would be considered market resource. Those are just sort of the bookends, and for each of the contracts you have we'd have to make a factual determination of what type of resource it was.

If the resource is a hydro resource, the owner of that resource will receive a decrement or reduction of its rights to buy power, unless that resource is serving its load or has been sold to serve the load of another regional customer. That's basically if you look next to the section 3(d) hydro, those are really the two uses of the hydro resource. And the rule is designed to prevent the export of hydro electricity from the region.

If the owner of a hydro resource shows us a contract where they've sold that resource to another regional customer to use in serving regional load, then basically the responsibility for meeting these tests will pass to the purchaser of that contract. And they'll have to meet the 3(d) test or the 9(c) test if its a thermal resource. We're actually trying to use that contract, really, as the mechanism to track through. We're trying to set this out so the buyer and the seller both know the rules. And if the seller wants to protect itself from a decrement, they need to be sure they're selling this for regional load. If the buyer wants to protect its right to buy Federal power, it needs to make that consideration when it purchases the power from the other party.

The other point I would make is that the rules on hydro resources apply to both existing and new hydro resources. There's no distinction basically on when the resource was built.

If the resource is an existing thermal resource, the owner of that resource will receive a decrement on its right to buy Federal power unless it can show one of three things: One, that the resource is a market resource as described in Bonneville's 1994-9(c) policy, and that's a very limited exception, basically of existing thermal resources that were built by utilities that were not buying power from Bonneville at that time, and could be exported, because they weren't built to serve regional load. A second exception is really the same one for hydro, that the resource is currently serving regional load. That could either be your own load or it could be somebody else's load. For example if you had a maximum net requirements as described here, but you didn't purchase that much during the subscription policy, we wouldn't decrement the amount you purchased if you showed that I had a right to buy 100 megawatts, I only bought 80 from Bonneville, and I'm using these other resources to serve that 20 right now. If you could demonstrate that you wouldn't receive a decrement.

The third exception is that you have a previous or current BPA decision to allow the export. Under our existing -- actually under our existing statutes we've made case-by-case decisions on whether resources could be exported or not under section 9(c) of the statute. And then in 1994 we published a policy that applied to the owners of the non-Federal participation, new owners of the intertie that described how 9(c) would apply to those owners, and there have been decisions made that certain resources could be exported under that policy. So if you come in and say, well, Bonneville, you told me I could export this resource for 20 years, we'd say, fine, that applies, there's no decrement for that particular resource.

If none of those exceptions apply there's still a set of tests that we've established for existing thermal resources you can come in to currently export the resource. And that's a demonstration, under the current situation, when you come in for the application. The resource is defined by the Administrator that cannot be conserved or retained for regional load. You can show that the resource was publicly auctioned, that everybody in the region had a right to buy that resource. It's basically a test that allows the customers to remove their capital from an existing resource. And basically anybody in the region can come up, take their capital and buy that resource.

The second test allows a customer to offer the resource for sale to BPA and its eligible customers at cost, plus a reasonable rate of return. The offer must be made for a period of one year or a longer term, basically of mutual agreement, in the sense that if you want a longer export, you have to say I'm going to offer it for five years at this price. And the one year minimum term is really based on our proposal that we would conduct an annual review of what you've done with these resources for export and what your loads were in the region, whether you still actually had loads to use to serve the net requirements power that you purchased from us.

If nobody in the region accepts your offer to sell, then the customer is able to export that resource for the period up to the maximum term offered. So if they've offered it for one year, they can export -- do monthly exports of the resource up to a one year term. If they've offered it for two years, they could export for two years. When you come up to the next annual review, if you haven't exported the resource for long-term, then you would again face the test. However, if you offered it for two years, and say I exported it for two years, here's the contract, I exported it, then you would have a previous determination and that would pass that year's test. The purpose of this second test, really, is to -- if a customer is going to maintain control of a resource in a region, an existing thermal resource, they need to offer it to basically all regional participants at cost.

The third allows Bonneville to assess the current market conditions and determine that no decrements are required because there's low market prices in the region, and it would be unreasonable to retain that resource in the region. If Bonneville is selling power at $20 and the market drops to 16, there's no reason really to -- we wouldn't want to decrement someone's sale, and we would make a determination that that resource couldn't be conserved and we wouldn't reduce the requirement sale.

That's really I think -- that's a short description of the 5(b), 9(c) policy. There's a set of principles in there that actually describes how you would implement those general concepts in practice. In describing that, we put together a set of flow charts -- the Federal Register Notice goes through and lists a set of principles under each of these areas that are really the core principles that lead to the results I'm describing. These flow charts try to show how we would actually take the principle and apply them to the facts of your system. Page 1 basically shows the initial determination of your net requirements. Page 2 shows the changes that could occur during the term of a subscription contract due to changes in your loads and resources. The first flow chart starts with a determination of your regional consumer load. The top line shows the treatment of the resources in the customer's current Firm Resources Exhibit.

The bottom line shows the application of the presumption to exports of existing thermal resources and hydroelectric resources. So I'm not going to go through and try to take this through step-by-step, but these are designed to try and actually take the resources on your system and flow through and show you how the principles would apply to your resources.

The second chart basically looks at how you would address changes in loads and resources on your system. There's an annual review conducted where BPA will examine changes in the retail loads of your existing system primarily due to retail access and the export of resources and whether there needs to be a decrement based on the export of resources. In addition, other changes can occur due to periodic loss of your resources or the annexation of new consumer service areas which could result in increases of requirement service if you have, in a sense, bought a product from Bonneville that covers increases in load growth on your system.

That's really sort of the broad overview. I'd be glad to try to answer clarifying questions about the charts, but I'm not going to try to take you through them. This concludes my presentation. I'd like to open it now to clarifying questions on the policies.

BOB CRUMP: If a customer manages to meet these criterion, and I had some questions about those, but I'll get to that in a second. But if a customer manages to get these criterion and successfully exports a resource, and so the effect is that they increase their net requirements on Bonneville, what's the rate that they'd be buying that power at?

LARRY KITCHEN: They would, in a sense -- the bottom line on this chart is really their maximum net requirements, which is -- between the shaded FRE area, and the question mark for the resources that are on the net requirements, as long as they meet these tests, they would have the net requirements at the lowest cost, they would buy without a target adjustment charge. And that's on the initial determination. Where you would buy at a higher rate is if you annex loads after the initial determination of what your loads are under the contract, then you'd face a target adjustment charge or if you lost a resource or a resource retired during the term of your subscription contract and you came to Bonneville for additional service during that term, then you would face a targeted adjustment charge.

BOB CRUMP: That would be the answer if that customer was a priority firm preference customer, right?

LARRY KITCHEN: Yes.

BOB CRUMP: What if they were an investor-owned utility?

LARRY KITCHEN: Probably one of the key -- for investor-owned utilities what we have proposed is we would sell a block of power to investor-owned utilities under what we call the residential load rate and that's basically a finite amount that we proposed in the rate case. Any additional service above that would be at the new resources rate, and that in a sense the proposal for new resources rate would look a lot like the targeted adjustment charge, where they would pay the cost of any additional services.

STEVE OLIVER: The network requirements for a priority firm customer is PF lowest cost-based rate. Net requirements only makes them eligible for either of this RL power, which is a settlement under the residential exchange, or an NR rate, which is a market -- essentially intended to reflect market.

LARRY KITCHEN: If they have large requirements, that doesn't mean we would be selling them that amount at the lowest cost rate we've proposed. In a sense their rate would be tiered.

BOB CRUMP: On the criteria that you've got listed here for exports allowed under section 9(c), I'm assuming that all of those have to be met, not --

LARRY KITCHEN: Actually they're all separate tests. You have to meet one of the tests.

BOB CRUMP: Just one?

LARRY KITCHEN: Just one. And the idea -- the difference between public auction, that's public auction of your ownership share of the resource, basically you're divesting yourself of the resource, and you're out of it, there will be a new owner. No. 2 is you're basically selling a rights to power from your resource for a specific term, but you're not divesting yourself of ownership. Both of them require basically a public process where everybody is eligible to bid. The difference between the two is that the public auction will basically be at market, whereas if you've retained control of the resource the sale needs to be at cost.

BOB CRUMP: Well, the auction, though, you said would be in the region.

LARRY KITCHEN: Well, everyone in the region is eligible to bid. It doesn't mean you're excluding other parties. It means you've put it out as an auction, everybody in the region has the right to buy that resource, but if none of the parties in the region put in a successful bid then it can be exported.

BOB CRUMP: I guess one more quick comment, not that I think Bonneville is unreasonable, but the definitions of reasonable or unreasonable in No. 2 and No. 3 is at Bonneville's interpretation, I assume.

LARRY KITCHEN: We would be interested in comments on that. In the 1994 policy we used cost plus a reasonable rate of return, and we are definitely interested in comments on what those are. That's almost a theoretical concept, and there are lots of different ways to measure that. The way the policy is structured right now is it's basically -- that the principle and the customer and the account executive would get in and decide, has that test been met.

STEVE OLIVER: Just to stay on that, though, what we intend to do is have something that's reviewable by sort of a jury of peers, so to speak, in terms of this kind of a test. If we looked at cost, there's -- I think there is prudent utility practice to look at cost for the output of a generating unit, and a reasonable rate of return, that is established by regulatory FERC commissions, for other products and services in that area, that would be paralleled or similar.

I think that those are the kinds of standards we're going to be using. Bonneville is not going to come up with an individual definition that is not consistent with the marketplace.

BOB CRUMP: That's what I said, I knew you were reasonable.

STEVE OLIVER: We haven't said what that is precisely. It's going to be a case-by-case, unit-by-unit look. We'd like to work with the utility or the company on that and find something mutual that would stand up to public scrutiny.

LARRY KITCHEN: And actually there's more information available for the investor-owned utilities, since they're regulated. I'm not clear what the standards are for public utilities, what's a fair and reasonable rate of return.

DANA TOULSON: So you would -- if we offered up a resource to BPA for cost plus a reasonable rate of return, BPA would in essence buy that resource?

STEVE OLIVER: It may or may not, but the offer has to be made to ourselves and parties in the region, in order for you to fill in behind it with a net requirement to buy Federal power.

DANA TOULSON: That's for thermal or hydro resources, as well?

LARRY KITCHEN: Hydro resources, our view of section 3(d) of the Act, cannot be exported from the region and still continue to buy Federal power to serve that load.

TOM SCHNEIDER: How does that treat system sales? Typically you're not simply dedicating an individual resource, although you could do that, but what about system sales?

LARRY KITCHEN: Generally I think what we said in the '94 policy was that system sales would generally be treated as hydro unless the utility comes in with a plan of service that shows that it's basically a thermal resource that they're selling and maybe they're buying from the market to fill in behind it. If you've got a thermal resource with the capability to support it, you can make a system sale and support it with market purchases.

HOWARD SCHWARTZ: Howard Schwartz, Washington Department of Community and Economic Development. My question is, is treatment of sales of resources and how that affects FRE. And I'm a little confused looking at the chart and what you said.

STEVE OLIVER: Excuse me. There are a couple of things that I don't understand this whole process, and that is as of what date is the FRE computed? And then second, in terms of changes to it, if you have a divestiture or sale of resources, does that effect your -- does that affect your net requirements?

LARRY KITCHEN: I think in the subscription policy basically it said we would sell power to public utilities to serve their consumer load in the region less the loads currently served by their resources. And what we had to do here is what's really meant by currently served? What we proposed is the resources that are in the current Firm Resource Exhibit for this operating year are the ones that are currently serving their load.

STEVE OLIVER: 1998, 1999.

LARRY KITCHEN: 1998, 1999, so what we're proposing is those are the resources and what you do afterwards with those resources you're free to sell them for the FRE resources, but won't change your net requirements. You'll be required to replace any sale of these say resources D, E and F on this chart with the purchase from the market.

HOWARD SCHWARTZ: That's what I thought, and that's what the top line of the chart says. But then over here it says, under No. 1 for exports allowed, public auction. Well, suppose you auction off part of your firm

-- part of your FRE, does that fit this?

LARRY KITCHEN: The way to read this chart is the exports allowed to resource B, but not to resource E. And I'll give you an example, like Portland General Electric, Portland General Electric owns Centralia, say resource E, and they auction it off, it wouldn't change their network requirements. They also own Coyote Springs, call that resource B, if they were to auction off Coyote Springs, it's not dedicated on their Firm Resource Exhibit, that would be an acceptable export.

HOWARD SCHWARTZ: That is where I was headed. I've been trying to sort out what the complications of the sale of Centralia is for all of the owners. And some are -- have multiple resources, some have many fewer. So the sale of Centralia would not affect the network requirements of the owners who are selling it. So like Grays Harbor PUD's net requirements wouldn't change, Tacoma's wouldn't change --

STEVE OLIVER: Just to clarify, one of the first things to look at if a resource is dedicated in 1998, '99 FRE, the only way the network requirements would be changed would be if that resource became obsolete, retired, was lost through some calamity or act of God of that nature or consent otherwise was given. Other than that those resources that are dedicated are considered to be always dedicated.

HOWARD SCHWARTZ: The general policy is that customers of Bonneville could not simply sell off higher priced assets -- I mean higher cost assets in order to get access to more Federal power?

LARRY KITCHEN: That's correct.

STEVE OLIVER: But just to address that. It really depends once again if it's in this Firm Resource Exhibit, not -- if it's not dedicated to firm resource load at this point in time, then if it met these tests, one of these tests, then it could be sold off.

BILL DRUMMOND: Portland General's announcement of, I guess, the retirement of their Sandy River projects, are those projects going to be considered retired or obsolete.

LARRY KITCHEN: We don't know. They would have to present the facts of those resources as to whether they could still be operated or not, and have to make a determination whether they met the statutory standard.

DANA TOULSON: Same question, what is the definition of obsolescence? Would it be simply physical obsolescence or at some point you can keep something running for a long time and keep patching it, but it's a hundred miles per kilowatt hours. So at what point is it an economic obsolescence the same as a physical obsolescence, and how will you make that determination?

STEVE OLIVER: We have talked about this, but we're interested in your comments on it.

Tom, would you like to address that?

TOM MILLER: There are two different constructs that you can use, one being an economic one, one being in effect a physical, practical one, if the watch is still running, keeps on ticking, then it's not obsolete. If it is impossible to operate it, then it is obsolete. So this is an issue we're taking comment on. There is a definition of obsolescence in some way in the existing 1981 contracts, but there again we've had not a lot of examples of resources going out of service over the last 18 years, and so this is basically a question of what should Bonneville's standard be. We're interested in finding out what you think about it, as well as the definition of retirement. And we think loss of the resource is pretty clear, our sense is that it's a catastrophic loss. We had an example, I think, with the Yelm dam washing out. And of course it's unable to operate. So a catastrophic loss is pretty clear. Loss of the contract, we kind of viewed that as the termination date of the contract, not -- and early termination, but basically the expiration date.

MARGIE SCHAFF: Margie Schaff with the Affiliated

Tribes, as well as with the Blackfeet Tribe. And I have a question about the changes in net requirements after a contract is in place, and in particular the renewable -- new renewables section. I was wondering if you could explain for me the tie between this change in net requirements and the fact that this is tied to Bonneville's conservation of renewable resources discount, which is limited to 200 -- the first 200 megawatts of new renewable resource. The reason I'm asking, maybe so you can address my question a little better, is the Blackfeet Tribe is in the process of developing a wind farm. And they are currently served by Glacier Electric, who will not be the entity developing the wind farm, but certainly will be working with Glacier Electric and neighboring utilities in doing that. Your requirements state that the resource has to be developed by the customer. If the Blackfeet Tribe were to develop a renewable resource and sell it to Glacier Electric, who is in their operating area, or even to another Bonneville customer in the attempt to gain the renewable resources discount, we would not want that to be prohibited by that being the 201st megawatt of renewable power, nor would we want that to be any kind of a roadblock in the development of that resource by its change in whether or not it would affect their net requirements.

LARRY KITCHEN: Let me describe sort of the basic thrust of the subscription contracts is that we're asking parties to come in and basically contract for a period of time for the amount of power they buy from us. As part of that in our rates we're offering a conservation and renewables discount, which for certain -- basically if you spend money on certain specific things we'll give you a discount on the power you purchased from us.

In those policies it then got to the question, if we did this, what about the resource? You've developed this resource do you take it and sell it on the market or do you sell it to somebody, in a sense, and did they leave a portion of their load to serve that resource up front in the subscription contract, in which case there's no issue. But what if they didn't? They contracted for all their load? What we did is create an exception to our subscription policy, which said for these renewable resources we'll allow somebody to come in and displace the sale to us with the renewable resource, we put a 200 megawatt limitation on that, because we're taking the financial risk that we can turn around and sell that power in the marketplace, and we wanted to limit that. We actually think the 200 megawatts will cover probably all the development, if it turns out that it doesn't cover all the potential development and there's no real financial risk, we could always go in at that point, change the policy and increase the amount. But we wanted the ability to actually assess those conditions when we got to it at that time. So that's really the purpose -- a purchase by Glacier, this would allow Glacier to go in and gain the discount by purchasing the renewable resource from the Blackfoot reservation, taking that resource they could either take the purchase and sell it on the market to someone and not affect their net requirement, or if they were unable to make that sale, they could take it and dedicate it to their load for a specified period and displace their PF purchase price under this exception.

MARGIE SCHAFF: So you're not required -- the customer is not required to be the developer of the resource, they can purchase the resource?

LARRY KITCHEN: No, and I think actually the discussions around the conservation and renewable discount, what we've tried to do in this policy is if the resource you're buying was eligible for receiving a credit under the discount, then it's eligible for this exception. So we're not trying to create any different rules than the ones created for qualifying for the discount.

BOB CRUMP: Bob Crump, Kootenai Electric. Do you have something in mind for a definition of nonhydro renewable, are you looking for input on that, too?

LARRY KITCHEN: I think what we have in mind is we're just being clear that the exceptions for -- the treatment of hydro resources are different than the treatment of thermal resources, and where we got into the exception in the changes section, we made an exception from the 9(c) test for new thermal resources, including new thermal renewable resources, but for new renewable hydro resources we can make an exception for requirements load, but we can't make an exception from the 3(d) policy. So the nonhydro renewable is probably anything that qualifies under the conservation and renewable discount other than a hydroelectric resource. And partly what we were trying to point out is, as I said earlier, if you use the renewable resources criteria for dedicating to load, one of the consequences is if it's a thermal resource it will be treated like an existing thermal resource, it's dedicated to serve regional load, and then to avoid a net requirements decrement, when you take it out again you'll have to meet the 9(c) test for the thermal resource or the 3(d) test for the hydro resource.

BOB CRUMP: Let me see if I understood you correctly. Use the renewable definition --

LARRY KITCHEN: If you dedicate a new renewable thermal resource to your load under the renewables exception, what would otherwise qualify as a market resource that you don't apply 9(c) to, because it was just going to be sold on the market, now that you've specifically dedicated it to your load under this exception, it's now going to be treated as an existing thermal resource for purposes of 9(c). So you then pull it off and sell it, you first have to offer it to the region at cost before you can export it. As you put all these rules together, and then try and actually look at the facts that might come up, this is why this gets so complicated quickly, because you add three or four facts together on different rules.

STEVE OLIVER: One other bit of background that's useful, because as you go through these, they seem extremely complex and onerous. I think most of the public utilities we dealt with we have this net requirements picture nailed down very well. And the investor-owned utilities that we've dealt with in the past, we've not sold a lot of net requirements power to because it's been NR or market type of power.

So one of the things I wanted to bring up here is a lot of this complexity I think will be getting into large complex systems with lots of generation, that we'll have to work with to establish these net requirements and talk with resources. In most cases the public utilities have established which resources were dedicated to load and which have not been, and maybe have gotten 9(c) exceptions for export, that type of thing. I don't think that's generally true. I think we're going to have issues, don't get me wrong, but I think there are a lot of rules, here. And what I'm saying is my guess is a lot of people are very familiar with how their resources have set up with these rules in the past and may apply. And so I hope as we go through these, and they are very complex, that people keep that in perspective rather than looking at it as a massive set of rules that we're trying to regulate or control or judge what's happening with people's resources, we're not. We think that people will bring in two or three of these cases, if they have two or three resources, they'll be familiar with the status of those, and there will be exceptions as things change or market conditions or the load levels of the customer changes over time. These can be a little imposing and seem fairly complex, if you try to take them all in at once, but I think each customer has a set of circumstances that they will be applicable to. We're trying to make it clear in terms of those circumstances. And each account executive -- we're not going to stand back from this in a regulatory sense, take these rules in a back room ourselves and decide how they apply. We're going to go out and work with each customer and talk with them and, I think, come to some agreements, so once again it will stand up to public scrutiny as to how these rules will be applied under a contract.

BOB CRUMP: I don't recall specifically, but what's the process for changing your Firm Resource Exhibit? How difficult is that, if it's based on submittals from utility annually, couldn't they change their FRE, and in essence change the classification of some of those resources?

LARRY KITCHEN: I think that was Howard's question earlier, what we're proposing here is starting with Firm Resource Exhibit, we're starting with your current one, and then we're proposing basically new rules which we're saying no changes from the resources in your current one. We're changing the difference -- in the past you could change it each year, take any resource in and out, and what we're doing now is saying no, we're going to freeze this moment in time the resources you're using.

STEVE OLIVER: It wasn't each year, there was some notice.

LARRY KITCHEN: Right. You had to give --

STEVE OLIVER: Right.

LARRY FELTON: Larry Felton, Okanogan PUD. This is all geared towards Firm Resource Exhibits, and I can think of some scenarios where you get into some nonfirm problems. As an example, if a future customer, public -- current public customer chooses to take SLICE, for example, and you have nonfirm associated with that Federal resource, and the trick of using SLICE is to fill in your winter peak with June energy, are you going to have some ability to track what they do with excess power that they can't use in their system to make a determination it's not exported or are you going to allow them to consider it nonfirm and get the best price they can in order to fully utilize the resource?

LARRY KITCHEN: I'll take a shot at that, and then I'll let Tom add, because he's worked a lot more on SLICE. My understanding of how this would apply to SLICE is we'll do a determination basically of your annual average energy requirement, as your net requirement, and that will set a percentage of the SLICE of the system you can buy. And I think then that gives you your SLICE resource that fits within the net requirements, and in our annual review we'll come in and see are you still serving the amount of load that that was based on or have you -- and you haven't exported any of your other resources that would result in a reduction of your net requirement right. Once you've established that, then under SLICE I think they're looking at some rules as to whether we could buy back the surplus in certain situations, but that would be part of your SLICE contract, it would not fit within the rules of 5(b) or 9(c).

TOM MILLER: I think that's basically right. We're still working through the SLICE construct. It's not set up for contractual language yet. The components of SLICE from Bonneville's point of view, that is the requirements service would be there would be a firm component that would vary with the system output. There would be a firm secondary component that is known and in fact predictable in certain periods of the year, and there is also a nonfirm component for basically whatever happens based on that year's water conditions. And the customer would be given the flexibility to try to manage its use of that to meet load, and of course the purpose is to meet load with it. But we can't mix the issue between what is the customer doing with its set of resources that we have to sort of flow through 9(c) here, as opposed to what you're doing with the Bonneville requirement service. So that's an important distinction to maintain. And a customer that has both resources and is buying a portion of SLICE, of course, will have to figure out a melded strategy of how to apply both its nonfirm -- it's firm and nonfirm from its own resources as well as from the Bonneville component to set up its operation and how to meet load.

What we're trying to track here, basically, is the customer's use of resource, those that have been dedicated to load and those that are not, and which have been offered on the market, and that's the purpose of this component. SLICE really poses us with a different set of issues, on how you're using the Bonneville component, but that's sort of over here.

One other clarification, I don't want people to leave with a misinterpretation. Under Bonneville's statutes Bonneville does not have the authority or the right to tell a customer that it cannot sell on the market or export a resource. The customers have that right. The way they do it and how they do it causes Bonneville to make certain determinations as to what you can buy from us. And if a hydro resource, for example, is exported that could have been used to serve load we can only sell power that is surplus to our system to back that up. We can't sell you firm requirement service for that. We're prohibited by law from doing that. So it affects the price and the class of power that you buy from Bonneville, but nobody should leave here with the impression that Bonneville can prevent you from exporting resources. That's a real important concept to have in mind. You can do what you want to do with your resources. There are contractual consequences if you've dedicated a resource in terms of pulling that off of serving load. And basically the customer remains responsible for providing a backup to that portion of load service. So that's important to maintain, too, that distinction.

And I guess the third point is there are some resources for some customers that are required by statute to be dedicated. Some are elective and some are required. And the ones that are required are the 5(b)(1)(a) resources, those that preexisted the regional act, so the Northwest Power Act. So I'm sure you're all familiar with those contexts, but that's sort of the groundwork we're basing this on.

HOWARD SCHWARTZ: Can I go back to the question of change in FRE, again. One of the things I'm puzzled by, and maybe you can clear this up, during this subscription process, the issue came up, in all the attempts to figure out what load the public power would place on Bonneville, various estimates were made and the rough allocations that merged and found their way into the subscription proposal and strategy, were assumed a certain amount of public load. And then in the last several months we've heard that the public load is likely to be higher, which is one of the problems that Bonneville is having with the DSIs and the like. And I guess I'm trying to understand how there could be a change in public load if there's no change in FRE, because that's what settles net requirements and then how -- and then publics would then presumably forego contracts they have to purchase from someone else and instead place their load on Bonneville. But the way I understand this, the FRE is locked as of 1998, '99. So I'm trying to understand how that works.

LARRY KITCHEN: I guess in the Federal Register Notice we actually have some explanatory materials about this, but the issues, there's a number of customers who, particularly in 1996 they took load off of Bonneville, but they went out and instead of actually dedicating that under a Firm Resource Exhibit, they just bought power from the market, or they displaced the Bonneville purchase with power from the market, and either the contracts are expiring and they're bringing that load back or they never showed that load in the first place. I mean a lot of it is just those contracts expire, and so they fit within the lost contract definition. I think it should be clear, one of the policies is if you know you've lost a resource, and could actually meet the standards, and do that up front in the rate case and come in and buy power to replace that lost resource in the subscription window, then you're allowed to do that at the lowest cost PF rate. So that's sort of where the load came back.

In November when we looked at how much public load we would have, the issue was, well, of the maximum requirements they could place on us, how much would the publics buy. And a lot of the assumption was, the market was about three or four dollars lower then than it is today, and the expectation was a number of public agencies had established new relationships, would want to diversify their supply, would find the risk of fish costs on Bonneville would mean they'd rather maybe pay a little higher fixed price than someone else than face the cost recovery adjustment clause. And since we issued subscription policy the market has moved up three or four dollars and there's a much wider gap between what Bonneville's projected costs are in the rate case and where the current market is. So that's led to the change in expectations.

HOWARD SCHWARTZ: That means that there were a number -- a number of public customers who were basically buying less power, less than their requirements would entitle them, less than they're entitled to, they're still entitled to that amount, now they're asserting their right to buy up to the entitlement?

LARRY KITCHEN: Yes.

STEVE OLIVER: The fact that we're sticking with the 1998, '99 Firm Resource Exhibits, that locks in the amount of generation dedicated to load. But we're not locking in the net requirements, itself. The load can increase over time.

LARRY KITCHEN: That's really it, in a sense, the new preference customer issue would lead to increases in load served.

GREG GILBERT: Greg Gilbert from Tacoma Power. In looking at the loss of resources or potential gains in load when we were charting with our account executive, Stuart Clark, he mentioned that we would be required to make known to BPA at some time prior to the close of the rate case that this would be happening and if it made it into the rate case calculations, depending upon your determination of the resources, we may be eligible for being served at the PF rate. And the question is, are the quantities that we give you an obligation or are they merely an estimate?

LARRY KITCHEN: For the lost resource calculation, basically if you want to take one of your resources that's in the Firm Resource Exhibit and basically say that I'm going to lose it the next rate period, we're asking you to come in and actually have that determination made so that we understand that in setting our rates. And the standards we're proposing in the Federal Register Notice are not different than the standards in your contract. So if you know today the resource is lost, then come in and let's make the demonstration now so we don't face the financial risk later that we'll have to buy some power to replace it. Doing that determination sets your maximum net requirements. That doesn't set how much you buy from us. You still, when you actually sign your subscription contract, 120 days after rate case, will decide whether you buy your maximum net requirements or some smaller amount. So that's what you would have to make a decision as to how much you actually buy from us.

GREG GILBERT: The fear would be that changes happen within our own system that require us to request of Bonneville more load than it appeared during the rate case, and that might or might not be -- even though it might be classic preference load, it wasn't in the rate case, and it would be served at a higher rate.

LARRY KITCHEN: Right.

GREG GILBERT: We have to get all our ducks in a row, then.

LARRY KITCHEN: We're saying if you think one of your resources is lost, and you want low cost PF service, come in right now and make the case, and we'll make a decision. You can do that under your existing contract, you don't have to wait for this policy.

GREG GILBERT: What's the last time that we can make that? What's the deadline on that, the time the rate calculation is made during the rate case or beginning of the rate case?

LARRY KITCHEN: We haven't really set a date, but basically we need to know that before we make our final decision on what the rates should be. If we find that a thousand megawatts of public load suddenly is going to go out -- public resources are going out of existence, then we would probably reflect that in the final rates.

GREG GILBERT: Another question had to do with the determination and maintenance of the net requirements. And I was curious on what BPA's interpretation was of the preference legislation. Does BPA view its obligation to insure a Federal customer does not increase its requirements as a result of export or does it view its obligation to reduce a customer's net requirements to the extent it develops market resources?

LARRY KITCHEN: Under which statute are you asking that question?

GREG GILBERT: Under the preference legislation.

LARRY KITCHEN: For regional hydro?

GREG GILBERT: Yes.

LARRY KITCHEN: I think our view of regional preference is that if you have load that you can use to serve that hydro, then it can't be exported from the region, so it's not an issue of whether your requirements increased because of development, it's if you have the load to serve it, you should use it to serve the load.

Are there any additional clarifying questions or should we open it up for comment? Greg, are you finished with your questions?

DANA TOULSON: Tacoma Power, Dana Toulson. On page 14 of your document you talk about how SLICE purchasers would be affected. And you talk about if the reductions cause the customer's net requirements to fall below the amount of power being purchased from BPA, the agency will implement the mitigation measure for retail loss specified in the customer's contract. What do you have in mind for the mitigation measure, given that SLICE now is not defined? What do you have in mind with the mitigation measures, and how that would be applied to other preference customers that might not be taking SLICE?

LARRY KITCHEN: What I was describing in the sense when you go in the annual review and your load's gone down, and you don't now have the same firm load to justify the percentage, in the subscription policy there's a set of retail mitigation measures, and what I was meaning is that under your contract you'd pick one of those measures, whatever mitigation you would have for retail load loss, and that would be the contractual mitigation implemented.

STEVE OLIVER: You may not have -- I think it's something that's an election by the customer to have a certain type of mitigation or some options, I think, is what we're looking at. Is it clear that every contract will have one or it may be elected or purchased as a mitigation measure for load loss?

TOM MILLER: The current subscription proposal has as part of it a set of three mitigation measures that would be available by contract to the customer. Now, whether all three of them would be in any one contract is probably subject to negotiation. But the three of them are basically conversion to a surplus sale, that is you're swapping out the requirement service for a surplus sale, if Bonneville has surplus available. The second is Bonneville remarketing the power and basically that's a first right of refusal of Bonneville to take the power back in that would have been made available to you and to use it for other load, and basically give you a dollar credit for that. In effect, if we have PF load we need to meet and you've lost load and we take it back in, you get the credit for the PF.

The third is an insurance or what's called an insurance product that basically I think provides a hedge on the potential loss of load, and would pay out -- the take or pay obligation. In effect you'll remain obligated for the dollar amount, even though you may not be getting the power, because you don't have the load. The reason for that is we're not authorized to provide you requirement service if you don't have firm consumer load to serve. So one of those three or possibly all three will be in the contracts for the customers, that's what the mitigation measures are.

LARRY KITCHEN: Are there additional clarifying questions or should we go ahead and open it up for public comment?

Does anyone have a comment they want to make?

STEVE OLIVER: We want to express our appreciation for you taking the time out today to come and talk with us about these policies, and we'll look forward to your comments, perhaps on June 2nd or in writing -- June 2nd in Portland, if you happen to be there or by June 11th in writing. And one other thing I want to remind you of, is if you want a longer public comment policy, we would consider extending this for some reasonable period of time, as well.

BOB CRUMP: Steve, is the information, the documents available on your web site, are they the same as what was in the Federal Register?

STEVE OLIVER: Patti is saying yes, they are, same documents. Also feel free to contact us, if you want certain parties with certain expertise that you've heard here today, get our phone numbers and contact us through the Bonneville general operator and we'd be glad to talk to you more about it if you're interested. Thanks very much.

(Public meeting adjourned.)