Council Meeting
Coeur d'Alene, Idaho
November 15, 2017

Chair Lorenzen called the meeting to order at 9:00 a.m.

Randy Hardy:

Ben Kujala introduced Randy Hardy.

Randy obviously has a very long resume in the industry. He has been doing consulting for many years, has been closely following California, and has a very strong perspective. And he has come to share it before the Council. Among the many accomplishments he has is that as a former BPA administrator, he's been in the hot seat and has understood the regional relationship in a very direct way. So it is my pleasure to turn it over and let Randy share with the Council his perspective which, as a continuing thought leader in this region with a strong understanding of our dynamic in this region, as well as how we relate to the California market and the California entities.

Hardy:
Thank you, Ben, and thank you, Mr. Chairman. I would start by thanking you for inviting me. I'm happy to share whatever knowledge I may or may not have with the Council and with others. In my current consulting capacity, working with clients or BPA, I view that as one of my roles to try to help talk about policy tradeoffs and policy choices that decision-makers have, whether that's Elliot at Bonneville or other utilities, the Power Council or whatever. Ben mentioned my 10 years at (Seattle) City Light. One of my first jobs in this region was the head of PNUCC. I worked very closely with Dan Evans, Roy Hemingway, and the initial Council in the early 80s. That contributed very much to my education as a beginning professional in this industry. I appreciated that time and I certainly learned a lot. That was a pretty formative time for our industry.

What I wanted to talk about today in a nutshell is what's going on in the California energy business, and how that might affect the Northwest and WECC as a whole. It's a fascinating social experiment that's occurring down there. Because California is probably 40 to 50 percent of the total WECC load, it inevitably will have major ramifications for what happens up here.

California passed, in 2011, a 50 percent RPS. Three IOUs are well on their way toward achieving that goal. They're currently at 30 percent of their power supply being supplied by renewables, and they have to reach 50 percent by 2030. That's the framework within which decisions are being made. The reality of the resource acquisition in California is that all wind that is possible to acquire, has been acquired. There are other wind sites in California, but they're all transmission constrained.

So the only renewable resource you have to get from the current 30 percent to 50 percent is solar. And you're already dramatically surplus in solar, so they're just going to make that worse. And that's just procurement of utility-scale solar. In addition to that, you have rooftop solar that's growing even faster than utility solar. California has by far the most generous net metering policies in the United States. So, if you have an income of $50,000 or greater, you'd be crazy not to put solar on your house. The tax incentives – both state and local – and the fact that you get the retail rate from the IOU when you sell it back to them, make installation of rooftop solar extremely attractive, and the PUC has made it pretty clear they won't revisit changing those policies until 2019 or 2020 at the earliest, if then.

You have a situation where you have flat or declining load growth in California. And you're growing solar at 2 GW per year. That's a combination of utility-scale solar and rooftop solar. And the percentage of what is rooftop and what is utility is changing. So the utility-scale acquisitions are slowing somewhat, and the rooftop is increasing because of net metering incentives. That's the situation that currently exists in California. One of the first consequences that will have for us, as well as for others within WECC, is that if you continue to acquire more solar to get to 50 percent, and continue to enlarge the solar surplus on one hand; and then on the other hand you have fracking, which is going to keep natural gas prices low as long as it continues, we're probably are looking at 10 to 15 years of power prices that are below 30 bucks. Now, I've been around this industry for 40 years. Predicting the future is a perilous endeavor, as you all probably understand better than anybody. But the factors are clearly there. Unless fracking is somehow discontinued, or California somehow abandons its march to a 50 percent RPS — neither of which seem very likely to me — you're going to have this enormous surplus that is going to force wholesale prices quite low, ironically, while retail rates go up, because all the solar costs you have with RPSs will continue to flow through to retail rates.

It's already had significant implications for Bonneville and for the hydro-based utilities in the region (Seattle City Light and the public generators) because they've lost an enormous amount of their traditional secondary hydro sales. The combination of low gas prices and the solar surplus has severely reduced spring hydro surplus sales. So you're spilling a lot more, and what you are selling, you're not getting the prices for that you historically obtained. That creates a considerable rate pressure for Bonneville and for all of the primarily hydro-based utilities in the region, and a comparable challenge.

What the solar surplus does in California is it creates two problems for the state:

The first is a midday surplus problem. In the utility industry, literally for 70 to 80 years, you've had a concept of heavy load hours and light load hours. Heavy load hours are from 6 a.m. to 10 p.m., with a peak at 1 to 2 p.m., or maybe 3 or 4 p.m. Light loads are 10 p.m. to 6 a.m.

The low load time in California is now 2 p.m. There is no more heavy load hour/light load hour paradigm. It's completely reversed. The peak load tends to be in the evening, when the sun goes down. Your evening activities are still placing a fair amount of load on the grid. So, that paradigm has completely changed. What you have is an ever-growing midday solar surplus. In the spring, loads are at their lowest, because you're not yet running air conditioners like summertime and you don't need heating for winter because the winter's essentially over.

Last April and May there were significant amounts of negative pricing and curtailments. What happens is prices go to zero, and then they go below zero. Negative pricing means you pay the buyer to buy it — kind of a novel concept, but that's what happens. With a tax credit, it makes sense to pay up to about $20 MWh and still run the plant, because you're still getting the tax credit. Particularly with the production tax credit, you only get the credit if you generate. So that's another dynamic. But that will continue to grow. You're going to continue to have increased negative pricing. Each of the IOUs has their own supply curve. They'll pay up to a certain point, and it depends upon the particular PPA they have with each individual solar provider, and then they'll curtail when no longer economic to do that. What you'll have is increasingly massive curtailments, not just in the spring, but they'll eventually spread year-round.

If you can imagine this, somewhere in the 2020-2022 time frame, you will reach in California a no-net load proposition. What's the load when you subtract out the solar and wind? It will be zero at some times in the year. What will we do in those circumstances? Talk about a brave new world. We're in a completely different place than we've ever been. You can solve that up to a point with massive solar

curtailments, and that's probably what is going to increasingly occur. And what the California ISO is worried about is that at some point it will produce a political reaction. It's hard to know what that political reaction is given that the politics in California are more complicated and less predictable than what we experience here in the Northwest.
So that's part of the dynamic you're looking at: The midday solar surplus continues to grow, it will continue to increase negative pricing and curtailments.

Member Henry Lorenzen: Can you explain curtailments?

Hardy: You trip the breaker and the solar plant is shut down. It's a little more complicated than that, but not much. You simply turn off with wind and solar. They're essentially "must-run resources," but when you have to keep the grid in balance, then they get curtailed.

The irony of this is you curtail so many megawatt hours of solar, which means you have to build that much more solar to make the 50 percent, which exacerbates further the midday surplus problem. So you're in this "chase your tail" proposition that's just crazy, but that's where we are.

One of the political dynamics you have in California — and this is a Hardy judgment, I won't attribute it to anyone else — is you have, from the governor on down, in the legislature, you have officials who voted for this 50 percent RPS, who are very reluctant to acknowledge that it has some significant problems associated with it. Because in the next primary, your opponent may just pop up and point those out. This is kind of that classic line from Reagan in the 80s that: "If there is no solution, there is no problem." That's essentially what's being practiced by the elected officials in California, in my view. That complicates the dynamic of trying to find a solution.

The other problem is that when the sun goes down and you still have the same, basic load. You just don't have solar generating to meet that load. So you have up to a 15,000 MW ramp that you have to cover in a three-hour period, from 6 p.m. to 9 p.m. That's an enormous ramp. And that's a challenge in and of itself. And you meet it, at least right now, mostly with gas-fired resources in California. But the problem is that most of those resources were procured pursuant to the CPUC resource acquisition requirements for the California IOUs, that have been in place for many, many years. Most of the resources used to meet that are a variety of combustion turbines, or combined-cycle units, that were procured many, many years ago. What you need are modern, more flexible resources — not just gas resources, but hydro — that can respond, not just in an hourly ramp, but in a five-minute, 15-minute ramp period.

The CAISO's so-called flex capacity stack, which is the group of resources that it uses to meet this ramp, 40 percent of those so-called flexible-capacity resources are long-start resources. You have to fire them up the day before to meet a five-minute increment the next day. To put it mildly, the CPUC resource acquisition priorities are completely misaligned with what the CAISO needs. Yet, in California, you can't change that without the CPUC, and the ISO, and the CEC (which is the agency that procures and sites for new resources) to change their procurement priorities. That looks unlikely to happen anytime in the near future.

Not only getting the three agencies together is a bureaucratic challenge, but you've got another dynamic going on in California that is severely complicating this. And that is you have the creation of what are called Community Choice Aggregators. These are individual communities, typically within a particular county, except they have no association with county government, who can form and go sign a power purchase agreement with Calpine, Exelon, NRG or some other marketer to procure resources independent of the IOUs. In part because of all these policies that IOUs have to pay for, California IOU rates are the highest in the nation. So there's a lots of incentive to form a community aggregator. You still have to use the IOU wires, but get your power supply independent of the host IOU, whether that's PG&E or SoCal Edison or to a lesser extent, San Diego Gas & Electric. Also, the CPUC doesn't have regulatory authority, or complete regulatory authority, over these entities. So what reliability standards, if any, they have to meet, and how their procurement is governed is a complete jumble at this stage.

So the dynamic that this is creating in California, is you have the CPUC completely distracted by trying to figure out how does it regulate the Community Choice Aggregators, and not paying much attention, in my view, to these operational issues that are occurring. And you have the California IOUs who are desperately worried that they're going to lose a bunch of load. So they don't want any extra costs that could become stranded costs. They don't want to change the resource procurement priorities, and be required by the CPUC to acquire new, fast-acting gas resources to help meet the ramp. They just want status quo until this whole penetration of Community Choice Aggregators can be sorted out. To give you an example, PG&E, which is probably the most exposed, thinks that five years from now, they'll have half of their load. PG&E is the largest utility in the country. That's an amazing phenomenon. You have the CCA formation distracting some of the key players, or motivating them in ways that are counter to solving the solar surplus problem, and that is not something that is likely to change in the near future.

Back to my comment that if there is no solution, there is no problem, you have elements in the legislature who are in denial that there is a problem. That the duck curve that you've heard about — that the belly of the duck is when the solar surplus occurs in midday — is all just a big hoax. So it is not a great environment. I certainly wouldn't want to be Steve Berberich, who is the head of the CAISO, right now. Because they're the only agency that is actually trying to solve the problem. Everybody is off doing other things, some of it explainable and some of it not.

Then, to layer on top of the politics of all this, you have the labor interests in California, who don't want to acknowledge the problem. And they don't want to procure any out-of-state resources. They want an all-solar path to 50 percent and they want it all to be in state so they can generate as many jobs as possible. And they have a stranglehold, in my view, on the California State Legislature. Who knows where it will lead? The signs aren't encouraging that it will lead to solving problems. So that's the physics of the issue and the politics that are complicating this.

One pretty straightforward solution would be to simply access Northwest hydro. Hydro is by far the most flexible resource that you can use. All you do is open a wicket gate and you've got it. And the CAISO's problems with the evening ramp in particular are not just a 3-hour problem, it's a within-hour problem. To give you some idea, the ramp at its maximum is 15,000 MW. But it's growing each year, because you're adding 2,000 MW of solar each year. That's just going to get worse. Right now, a single hour of the three-hour ramp is often more than 50 percent of the entire three-hour ramp. A single, 15-minute period of each hour is often more than 50 percent of the hourly ramp. A single, five-minute period of the 15-minute of the market is often more than 50 percent of the 15-minute ramp. So you've got not only a three-hour exponential ramp, you also have an enormous variability of several thousand megawatts within each hour and even within each 15-minute and, to some extent, each five-minute period. So you need resources that can really move and move quickly all over the place.

CAISO just last week took the first step, albeit a modest one, to address the ramp issue. They have in their initiatives catalog for 2018, which came out last week, an initiative to look at a day ahead, 15-minute market capacity product. They'll develop this during 2018 and presumably put this into effect in 2019. That's the first time CAISO will be paying for capacity in its 20-year history. That's a step in the right direction. If you have a capacity payment that gives Northwest hydro providers more time and more assurance that they can get the financial returns they need to sell. It doesn't make a lot of difference in Q2, because the capacity comes with all the energy associated with runoff. In Q3, it's up and down depending on temperature, but it makes a big difference in Q4 and Q1, where you essentially face discretionary decisions of do I sell or do I store? If Bonneville, Powerex, Seattle and the PGP group can get an actual capacity payment, chances are they can bid into the day-ahead market to do that, which they can't now. They'll at least get some Northwest hydro. That's a modest step, but at least it's moving in the right direction. Ultimately you have to change your Resource Adequacy policies to procure more flexible resources, some of which could very well be hydro. I would commend to you some of the PGP studies that have been done— I'm sure Ben has copies of them — both on carbon pricing in the region and Chelan did one a couple months ago that looked at if you substituted 1500 MW of Northwest hydro instead of California thermal to meet the evening ramp, you would save about a half-million tons of CO_2 per year. It's not just cost effective; it actually helps them with their goal of reducing CO_2 emissions. But again, you have the labor interests and others that don't want anything out of state, so there's political opposition to that, and it requires, at least in some circumstances, multiagency approval — which is hard for the CAISO to get, given that everybody is going in a different direction.

So that's the basic circumstance. What will that produce for the Northwest? Continued, low, power prices. Bonneville is already well-above market. Bonneville's basic wholesale rate is $35. The market, a 10-year strip on a raw Mid-C price is probably $25, but that's not the right comparison because it doesn't include transmission or reserves. It's not a fully delivered product. But when we add those in, the fully delivered product price is more like $30 for a "market purchase" versus $35 for where Bonneville's rate is. And Bonneville's rate is going to continue to creep up. Bonneville is above market. Fortunately Bonneville has take-or-pay contracts, which don't expire until 2027.

I was the one who lived through the last crisis in 1995, where we had the same problem, albeit a much more temporary one. We woke up one day in April 1995, after deregulation, and our wholesale rate was $28, and Enron was offering five-year contracts to our public and DSI customers at $15 to $17. That's a problem. We broke all kinds of political china and got a lot of help from Senator Hatfield. Fortunately we were able to stabilize that and avoid missing a Treasury payment. In the process, we amended all of our contracts to make them take-or-pay.

Elliot's got stability in the near term. But he's got to start thinking now that, if we're correct, and low power prices are going to continue, do I start to take steps now, anticipating that come 2027, if I'm still in this circumstance, I'm going to have some pretty dramatic diversification. That's certainly what happened when I went through this thing in 1995. You've got to look at that and you have two choices: One is to sit and wait two to three years to see if the California market develops sufficiently, where you can sell big quantities of hydro capacity and other products to get the revenue return that you need to make up for some of the losses you've incurred and keep your rates in check. Or, do you do some long-term deals now if you have some "surplus power" that you can sell to one of the Northwest IOUs or maybe one of the marketers.

There are some interesting strategic choices that the agency will face in the next five years. That's the kind of circumstance: continued low power prices, implications come 2027 (or probably earlier than that for Bonneville) and, of course, financial pressure across the board, which will leak into other areas such as fish and wildlife, and other kinds of things because it's one budget that the agency is struggling with to be financially stable and to make decisions that are politically sustainable.

So you'll have those kinds of choices and continued financial pressure on Bonneville on one hand, but then you'll have a whole bunch of operational choices. By 2020, you'll have daily reversals of flow on the intertie. That hasn't happened in 25 years. That hasn't happened since the early 1990s, when I was Administrator, and we did seasonal exchanges. Earlier than that in the 1980s, when I ran Seattle City Light, we did seasonal exchanges. That's one of the main reasons why the Pacific Intertie was built. It was to dispose of the spring runoff hydro surplus and do seasonal exchanges, to take advantage of the seasonal diversity between California and the Northwest. You send power south in the summer to help run California air conditioners, and you get back load in the winter when their load isn't has high and you need it for winter heating loads. You'll have the same thing happening here, except it will be daily instead of seasonally. You'll send power south in the evening to help California with the evening ramp, and it will come back the next midday. It's not happening now because the solar surplus is not yet severe enough. In addition to all these other quirks, California has a $10 export fee. There's a lot of reasoning behind that, but ultimately that will have to go. Because when you have negative prices, all you're doing is taxing your own consumers another $10/MWh. So one would think that wouldn't stay around that long. But you have those kinds of complications and those kinds of operational challenges. So when you have daily reversals of flow on the intertie, I can't tell you how that will affect flows on the Bonneville transmission network, except it will. And whether you'll have congestion in spots where you've never had it before, or maybe it will help. But you have a whole range of transmission issues (in addition to the South of Allston congestion that Bonneville is struggling with right now) that will start to occur.

What are the solutions going forward?

The CAISO had its symposium about a month ago in mid-October. The CAISO board put out a white paper that was their view of the trends in the industry. I'm sure Ben has it or could get you a copy of it. I suggest you read it. It gives you a very good view of what's going on in California. It identifies trends, which are general industry trends, not unique to California: More decentralized power procurement, less use of gas, more penetration of renewables, and a list of eight different things. Then there are proposed potential solutions. It's a fascinating mix in the solutions section of the paper of very detailed and very practical things that can be done, like acquire more flexible capacity and access out of state resources. So you can procure Wyoming wind or Northwest wind that has a load shape typically generating in the evening and the winter that compliments California solar load shape in ways that get you to 50 percent, but minimizes the cost of it and doesn't exacerbate solar problem. That's prevented by other California legislation. And regionalization: expand the CAISO to be a regional ISO, if you will. Again, that would help significantly, but here are significant governance challenges that are in the way of that. So it has a set of solutions that are quite detailed and on the mark.

Then it has another set of solutions that I would charitably call aspirational (others would call them unicorn chasing) that are much more problematic. There is a heavy reliance on utility-scale storage. That's coming, but in the next five years, I don't think so. With a wind resource, if you get viable utility-scale storage for two to three hours, you can turn a 30 percent capacity factor wind plant into 70 to 80 percent capacity. With solar you need something overnight. You need 12-14 hours … we're 10 years away from that. There was an excellent article in this week's Clearing Up/California Energy Markets that S&P put out saying that commercially significant large-scale energy storage is 10 years away, and the logic for that. I would agree with that. We'll get there, but it is not easy. You do have viable storage, or will have shortly, at the residential level. Tesla's Power Wall technology coupled with the solar panels is a good example of that. But that is behind the meter, it's disaggregated and you have no way to control it. It benefits the individual consumer, but it's not going to help you without massive changes in the distribution systems, which even if you could accomplish them, are many years away before CAISO has any kind of meaningful control.

So you have a heavy reliance on storage technologies, which don't yet exist in any commercially viable form, and the second thing is an assumption that you'll have four million EVs on the street by 2030 in California. I think the current figure is 300,000. Good luck with that. That will really help. Not only will you have four million EVs on the street, you'll have the ability to precisely control when they charge and when they don't charge. That's a degree of control that's pretty unique, even for California. You can incentivize people to do certain things. But having that many of these in the first place, and then being able to control when they do and don't charge for the benefit of the electric grid (as opposed to consumer preferences), that's a social experiment that will be interesting to watch. You have a category of things that are already there that you would need to solve the problem. A more realistic set of measures would probably be … not to posit a full-scale CAISO expansion — that will eventually happen, but that's more of a five-to-10 year away proposition due to all the concerns about governance, and the some of the issues associated with Bonneville being part of that. If the problem gets bad enough, you could certainly increase your access to Northwest and other resources fairly dramatically. You have an EIM that's functioning pretty well right now, that helps, but that's only a five-minute market. One of the reasons why California is going to look at a 15-minute market day-ahead capacity product is because to transact in the five-minute market, you need what's called dynamic transfer capability on the Intertie. There's only 400 MW of DTC on the Pacific Intertie. It might go to 600. If you go to the 15-minute market, you have the full, 4,800 MW of Pacific Intertie you can use. With the five-minute market, you can only use 400 MW. So if you're going to address your evening ramp problem, you need full access to the full value of the Intertie. Probably in a couple of years, Bonneville will change its practices to get 15-minute scheduling on the DC, so the full 7,900 MW of Pacific Intertie will be available to the 15-minute market. Those are solutions. If you get rid of the export fee, if you rely more heavily on hourly and 15-minute market transactions out of state, and if you get rid of the legislative mandate of the category of renewables that effectively prevents much renewable importation from out of state, you'd go a long way.

That's not something that requires a regional ISO. That could be done tomorrow. The impediments are California's own regulatory impediments, the export fee and the lack of capacity payments, in particular. There are solutions, or at least movement toward solutions, but they are ones that are not politically available right now.

I'd end by saying something I've said many times before: This industry is in the midst of enormous technological change. You've seen that, you've heard that. One vignette unrelated to California illustrates that best. Seattle has, by almost every account, the most commercial construction downtown of any city in the United States. Go up the Space Needle and count the cranes. There were about 20 the last time I counted. Commercial load is 40 percent of Seattle City Light's capability. And it's growing. You have more construction going on to create more load, and yet Seattle City Light's loads are going down. And the reason they're decreasing is LED lights and more sophisticated HVAC system controls. That tells you something about where loads are going generally. You all are the premier load forecasters in the region. I was telling Steve Crow earlier to look at the LED light penetration and what conclusions can we draw. PGE still thinks they're going to have 1 to 1.5 percent load growth in Portland, which has an enormous effect on the South of Alston transmission problem. I'm not so sure. But that's an area with the conservation targets you've set and your load forecasting, where the Council could make a unique contribution that is very germane to sizing this problem. But in any case, those are the kinds of changes that are occurring. We're in the midst of an enormous amount of change, and it's a fascinating time to be involved in the industry, but the outcome of that, given where California is or isn't, will have an effect on all of us.

There are interim solutions that will help. Currently, they're largely precluded by politics in California. But as the problem gets worse, and the renewable curtailments get more pronounced, I think that will change.

Another thing that's lurking out there is you have a significant chance of a major reliability event in California in the next five years. If that happens, since I'm the guy who caused the last event in California back in 1996, that will change things in a hurry. The problem is, when that occurs, people will be far more interested in finger pointing than they are in solutions. It provides a motivation, but what the solution that comes out of that is anyone's guess. Having lived through one of those, I don't wish that on anybody. But there are significant risks that it could happen again.

With that I'll be happy to answer any questions.

Member Bill Booth: For me, you really put the California situation in a perspective that was very easy to understand. I know it's much more complex. This region, because of our hydro resources, is in decent condition and would logically be a solution for California to help in the evening with that quick ramp up. Is the current intertie transmission infrastructure set up to handle the five to 15-minute surge into California? Or would it take additional infrastructure. We're also seeing a large increase in solar in this region, some states have solar goals as well. In Coeur d'Alene, I get radio ads for rooftop here where it's a cloudy, wet climate. Do you see the same problem developing here?

Hardy: To answer your first question, yes and no. The EIM only transacts in the five-minute market with whatever excess transmission capability is available. You only have 400 MW of DTC on the AC portion of the Intertie that's available for those kinds of transactions. So there are real severe limits for the EIM for the five-minute market. But for the 15-minute market and hourly market, you have the whole Intertie capability … with the exception that we don't yet have 15-minute scheduling on the DC, but that will come. You have the whole 7,900 MW of the Intertie for hourly transactions. And you have the whole AC (the 4,800 MW) and then in two or three years, the DC that will be available for 15-minute transactions. All of which would help if you had a bidding system in California that would pay for capacity. That's the problem. CAISO offers a capacity payment, say it expands … it implements the day-ahead product and then it expands it to an hourly product. This would have to be a set of transactions outside the normal bidding framework, which is a significant challenge for them. Ultimately, you clearly have the capacity to do that. If the problem gets severe enough, by far the easiest thing for you is to access existing Northwest hydro capacity. And you have plenty of sellers: Powerex, Seattle, Bonneville, the public generators and frankly, the IOUs.

Idaho Power and Avista are still predominantly hydro-based utilities. Between Hells Canyon, Noxon and Cabinet Gorge, they have significant hydropower capability. But the IOUs can also use their thermal capability. Let me give you a vignette that illustrates what can be done: Right now, PacifiCorp was the first participant in the CAISO EIM. The way they're operating their coal plants is amazing. They're doing this in the five-minute market right now. When the midday surplus comes, they back off to 20 percent. And when the evening ramp comes, they ramp up to 90. They're printing money. And they're operating coal plants in a way we never dreamed was possible. But they're doing that. Eventually, due to lower power prices, those plants are going to be retired in the mid-to-late 2020s. But that's the kind of operation you'll find with the IOUs and their thermal. And that's the kind of operation you'll find with those publics and IOUs that have hydro projects with significant storage — Powerex, Seattle, Avista, Idaho, and Bonneville to a lesser extent, because fish constraints have essentially removed most of the operational flexibility that Bonneville has. They can still sell some hydro. But the challenge you have, and why you need a capacity payment, is even when you have storage, you need to set up your system three or four days ahead of time. You need to take actions on a Monday to deliver something on a Friday. A cubic foot of water out of Grand Coulee doesn't pass Bonneville until a day later. So you need a fair amount of lead-time to set up your hydrosystem, which the five-minute market does not provide you. That's why capacity payments are important. It not only gives you more money per se, it allows you to set up your hydrosystem in advance to maximize the amount you can deliver to California. So it's better for you, but it's also better for the ISO because they get more of the most flexible resource that's available on the West Coast.

So that's the answer. Outside of five-minute market, yes. Within the five-minute market, very limited capability. You can theorize about Bonneville joining the EIM, but aside from the politics, BPA has two-to-four years worth of transmission automation work to do before it can even think about joining the EIM. So it's a moot point. Not that they aren't thinking about it, but there's a huge amount of transmission automation work and IT work that would have to take place before they would be remotely capable of participating in the EIM. I've lived through this. That's the physical reality of that system.

Relative to your question about solar, I'm not an expert in Oregon, Idaho and Washington solar, but what I've seen of the data, it's mostly PURPA projects. I doubt that much of that will come to pass. With rooftop, it's a different animal. It just depends on what your net metering policies are, and what the incentive structure at the state and federal level are, and that could well move. The fact that you have this enormous penetration of solar in California, which will keep prices low, I doubt that you'll see much utility-scale solar that will actually come to pass. And you have plenty of projects. But having consulted for a few of these folks, it's the same with the large wind companies. They come to you and they have lots of data. This is probably more so with the wind folks, but it's the same dynamic with solar. They have 10 years worth of wind data for a particular site. Talked with GE or Siemens, and they have the latest turbine design and everything else. But they haven't thought about transmission. Suddenly, they come in there and say they're ready to go, and you find out they have to build new transmission and that's a 10-year project. In real estate it's location, location, location. For renewables it's transmission, transmission, transmission. By and large, the smaller guys don't think about that until the last minute, and they can't do it. The short answer to your question is I don't see much utility-scale solar anywhere in the Northwest. Some PURPA projects have already gotten through the Idaho Power and Idaho PUC conundrum, but I just don't see that happening much elsewhere because the California prices have so depressed the prices you can get for most large projects, and the transmission issues you typically have of interconnecting to Bonneville. I doubt there will be much penetration.

Member Lorenzen: You mentioned the DC intertie, is that capacity 7,900 MW, or is that combined AC and DC?

Hardy: That's combined AC/DC. The DC is 3,100, and to go to 3,220 here in another year, and the AC is 4,800. There is a possibility you can increase the DC capacity to 3,800, but that involves raising all the towers on the California end and completely reconfiguring the southern terminal, and that's about a $1 billion project for another 600 MW — probably not something that's going to happen real soon.

Member Lorenzen: You mentioned that there's a potential for Northwest wind to complement California solar. Is that constrained in any way by the Intertie?

Hardy: No. Intertie space is completely allocated out. Avangrid is one of my clients, the biggest wind developer in the Northwest. They have plenty of Intertie capacity. They can build more wind and sell to California, but the problem you've got now is you have three categories of renewables. It's very restrictive. The only renewables out of state that a provider can sell into California is in real time, within the hour. That's pretty difficult to do. I think eventually the Californians will have to get rid of those three categories. That's a legislative decision in their part. But the labor interests don't want that to happen because then you go out of state, and lose the jobs, and you all can extrapolate the political implications of that. But ultimately that would have to happen and, if that happened, just like pre-2010, with the 20 percent RPS, you saw a lot of wind development up here. The whole Shepherds Flat is sold to SoCal Edison, that's 850 MW. You'd see similar developments, in my view. You might see more Montana wind that would come, but you have to resolve come intertie constraints there first. But that tends to be a better wind resource. But typically that involves two or three wheels, and the pancaked wheels eat up the 40 percent capacity factor advantage over the 35 percent Gorge wind pretty quickly. But you'll probably see a mix of Montana, Gorge and Lower Monumental wind. You might see some Wyoming wind, but that would involve construction of a several billion-dollar transmission line that I think is more problematic. But you probably would see some New Mexico wind, because you do have existing transmission capability, particularly with the retirements of coal plants at Four Corners. You could see some significant New Mexico wind, that's pretty good wind and would have a transmission path to get to Southern California.

Member Lorenzen: Oregon also has a 50 percent renewable standard. It may not be the same as California's. Do you anticipate that Oregon will face some of the similar issues that California is facing?

Hardy: I would hope not. If you're smart about it and you're PacifiCorp, because you have service territory all over, you can go acquire Wyoming wind and get that to count. Wyoming wind tends to be nighttime peaking and winter peaking. PGE, I would expect, would primarily look at Northwest wind resources. They've looked at that, they're looking at Montana wind, both of which have load shapes that tend to complement, rather than exacerbate, the California solar surplus. So I would expect that would be the approach that the IOUs would take.

Member Tom Karier: The Council is particularly concerned about Bonneville's financial situation now and especially in 10 years. As you said, if things continue with low prices, and they continue to carry the large debt burden that they have today and other costs, they're potentially facing bankruptcy as a government agency. And that's not what the Northwest needs or should have. The ways out of it are more markets, better markets for Bonneville. Not just more sales, but at a better price. I'm just skeptical that California will help us out in any way. The idea that we're waiting for them to set up the right market, that we'll be able to sell our hydro and get the actual value of it in energy and capacity might be overly optimistic that they'll do that for us. I'm thinking about the day-ahead capacity markets. Obviously capacity markets are what we need. But don't we need something longer that provides more assurance at a higher price? We need a six-month, or a six-year capacity market and assurance. If we're just dumping in capacity a day ahead, we're just dumping in surplus energy again, and not going to get the full value. Should we be thinking about that? Can we design markets or pressure markets to serve our needs, rather than California designing markets that represent their needs?

Hardy: Yes, is the short answer. I did not mean to suggest waiting for California to develop a market was the only solution, or even a desirable solution. I was trying to sketch conceptually the two pathways that you've got here, recognizing that they are not mutually exclusive. I think further developments will occur in California because it's inevitable that the solar surplus will create the need to do that. And Californians will not accept the massive renewable curtailments that will be the eventual consequence of just letting things continue the way they are. But that isn't alone sufficient. You need to do that, you need to take advantage. Elliot has done a good job of working with Steve Berberich and the CAISO. But for Bonneville's urging, I don't think the CAISO would have even started to look at the 15-minute market. That's largely Elliot personally doing that. Now there was a lot of support from PGP, Powerex, Seattle and lots of other hydro providers, but 80 percent is Elliot himself lobbying with

Berberich to make him understand hydro. That being said, you do need to look at longer-term transactions with Northwest IOUs or with marketers. BPA has the legal authority to do a five-year power sales contract with an IOU, and a seven-year ability to do it with a marketer. And you could do either one of those, and you could make it evergreen and roll it forward. And you could sell — this is Randy Hardy's view not Elliot's — you could do a five year contract with a Northwest IOU, or a seven-year contract with a Northwest marketer, and get something greater than 35 bucks for it. You could make it a fully dispatchable hydro product. That's the key. You could provide the operational flexibility that would make that $35 worth paying. Even though the market is below $30, that is just for a basic block of energy. That's doable in my view. I know that's one of the things that Bonneville is starting to look at. Part of the challenge is it has to be surplus, because public power has a call via the preference clause, but you may have some ability to carve out "surplus power" prior to the contracts expiring and people diversifying.

I'll give you an example: In the last couple of months, Bonneville went through a major exercise with Cowlitz PUD for the NORPAC load. NORPAC is shutting down 100 MW of its paper processing, supposedly to modernize and come back in a year or two. Whether that ever happens, who knows? But if they don't come back, there's 100 MW. And if you have flat load growth, there's 100 MW you could sell to somebody else for a better price. You've got things like that, where I think you could define some amount of surplus power that you would be able to sell on a longer-term basis.

Member Karier: Couldn't Bonneville identify even more of that through its energy efficiency programs and demand response? It could augment that.

Hardy: Yes, energy efficiency will help in the course of your own load forecasting and conservation work. If you could forecast forward what LED lights will do, relative to what your load forecast is going to do. Right now, I don't think BPA has fully sold out its Tier One power. It probably has contractually. But the reality operationally, is that loads are continuing to be flat or declining for the most part, and I think the effect of those new technologies will increase over the next 10 years in ways that create more surplus you could sell.

Member Karier: I like idea of working with Northwest IOUs rather than waiting for California to give us a break.

Hardy: I'm not suggesting waiting for California. BPA is still in court over the 2001 energy crisis. I worked for the California Department of Water Resources during that time. Bonneville saved their ass. They would have had twice the number of curtailments had Steve Wright not been willing to do the two-for-one environmental exchanges. The Californians who were there at the time recognized that. The lesson learned from that is that the California attorney general is a separately elected official. He doesn't get points or kudos for supporting out-of-region providers, he sues them. And if you have a problem with California, that same exact dynamic will happen again. So your caution is well taken.

Member Jim Yost: The situation we have in the Northwest now is do we remove the four Lower Snake River Dams and we have transmission constraints from Bridger west, with two major transmission lines under consideration and development. But even though Idaho Power has 480 MW of solar, it's difficult to find transmission pathways to move it to California, even though we do move some south and west. We're transmission restrained. PG&E can't even replace Boardman coal with a gas-fired plant. So if you take out the Snake River dams, I don't know if we can replace them with gas, unless we line them up on the Idaho border.

Hardy: I've tried to make a practice in my 20 years of consulting to stay away from fish issues, because it's just so depressing. All I'd observe is the factoid that's often ignored when you talk about taking out the Snake River dams, is yeah, they only provide five percent of the region's energy, but they also provide 16 percent of region's generation capacity. That's why they're important, and that's what you're going to need. We're awash in energy, thanks to the California solar problem. It's capacity that we need and taking those dams out, the capacity replacement (unless someone invents the next, great storage technology) is going to have to be a CT. So you're going to end up with more combustion turbine construction to replace them regardless. It underlines the importance of trying to keep those facilities, at least in the midterm, until some of this stuff sorts itself out.

Let me offer another, quasi-political observation. Again, this is something Ben should provide you. PGP has just done a really interesting study. E3, a consulting firm out of California did it for them, that looked at a cap and trade system for the Northwest versus a 50 percent RPS, versus a no-new gas scenario. A 50 percent RPS is twice the cost for half the savings of a cap and trade system. So if your goal is carbon reduction, you want cap and trade or a carbon tax. You don't want RPS. RPS hurts things. It especially hurts the Northwest. If you do a cap and trade, you actually raise the prices for existing hydro, which is an advantage to Bonneville and others financially. And no new gas doesn't do a damn thing. You get virtually no CO_2 savings, or a miniscule amount of CO_2 savings, for about the same cost as if you did cap and trade. You could read the study and make your own judgments. It's a very interesting piece of work relative to some of the choices, particularly Washington State, will have.

Member Karier: That confirms the results in our Seventh Power Plan too.

Hardy: I'm sorry I'm not as familiar with that. Whether Governor Inslee listens or not, we'll see. It was just a very interesting piece of work, especially since it complements what you've already concluded in the Seventh Power Plan. That's the kind of guidance policymakers need when they're looking at the tradeoffs. As California is dramatically illustrating, an RPS is a very inefficient and costly way of getting to carbon reduction. And ultimately, whether you even get there, is a good question. Because if the EVs don't come in and save your ass, what you're going to end up with, when the older CTs get retired, is you're going to have to build all kinds of single-cycle units to meet your evening ramp. You may actually increase CO_2 in California with that kind of an outcome. Crazy, but that's where you can go if you're not careful.

Member Lorenzen: Ben, can you get access to that study?

Kujala: We're still working with PGP on the scheduling, but we're going to have them present directly to the Council. It's in a future Council meeting.

Member Lorenzen: Do you have access to the study? Is that a printed study?

Hardy: It was posted last week on their website. If I could leave you with two thoughts: Read the PGP study. There's a stack of things from a summary to extremely detailed, so you can pick your level of specificity. Read the CAISO issue paper that they prepared for the symposium. Those two things will give you a really good view of both what works and doesn't work in the Northwest, and the California view of the world. And you can draw your own implications for what that means for us.

Member Lorenzen: Ben, can you get the site for that? Randy, thank you very much. It's a pleasure to have someone with your knowledge to come talk to us and spend an hour of your time.

Hardy: It’s a pleasure. The reason I do this is I’ve been around awhile. I’m in my early 70s. I keep doing this because it’s fun, given all the changes going on. I view my role here as not just doing good for my clients, but trying to help the region out. Whether that’s Bonneville or you all or other regional institutions to at least help focus the trade off choices for the policymakers. The agreement I have with all my clients is I’ll help you out with what you want, but I will look for win/win solutions for you and BPA in particular. Seventy or 80 percent of the time I can do that, and the other 30 percent you’re on your own. Fortunately, I have a group of clients who accept that as a going-in condition. As long as I can continue to do that, that’s fine.