Public Meetings for Docket I-15-001

The RCA opened Docket I-15-001 to gather information and comments from the public to assist it in responding to the legislative Railbelt transmission system inquiry. Transcripts of the series of eleven Public Meetings and presentation slides are attached.

April 8, 2015

A presentation made by Dr. Antony Scott of the Alaska Center for Energy and Power, *Overview of Work for the Regulatory Commission of Alaska*, is attached to the public meeting transcript.

April 22, 2015

Presentations made by Judge David A. Lawrence (regarding comments) and Jay Layne (regarding reliability) of the Regulatory Commission and Dr. Antony Scott of the Alaska Center for Energy and Power, *Reliability- One Aspect of an Efficient and Effective Railbelt System*, are attached to the public meeting transcript.

April 29, 2015

A presentation made by Dr. Antony Scott of the Alaska Center for Energy and Power, *High-level Modeling of Some Costs and Benefits of Change*, is attached to the public meeting transcript.

May 6, 2015

A presentation made by Dr. Antony Scott of the Alaska Center for Energy and Power, *High-level Modeling of Some Costs and Benefits of Change (part 2)*,is attached to the public meeting transcript.

May 13, 2015

A presentation made by Dr. Antony Scott of the Alaska Center for Energy and Power, *High-level Modeling of Some Costs and Benefits of Change (part 3)* is attached to the public meeting transcript.

May 20, 2015

Presentations made by Erin Whitney, *USO Governance Structures* and Issues, Dr. Antony Scott of the Alaska Center for Energy and Power, *Policy Decisions: Towards an Efficient and Effective Railbelt)* are attached to the public meeting transcript.

May 27, 2015

Other than the Commissioners, there were no speakers or presentations at this meeting.

June 3, 2015

Presentations of James Galvin, Teneo Consulting, for Chugach Electric Association, Inc. and James Trent and Davis LeVee for the Municipality of Anchorage d/b/a Municipal Light & Power are attached to the transcript of the public peeting.

June 17, 2015

A presentation made by Dr. Carl Petersen of NERA, consultant, for Chugach Electric Association, Inc. is attached to the public meeting transcript.

June 24, 2015

The presentations of Bob Day and Mikel Salazetti of Homer Electric Association, Inc. are attached to the transcript of the public meeting.

June 29, 2015

Other than the Commissioners, there were no speakers or presentations at this meeting.

STATE OF ALASKA
REGULATORY COMMISSION OF ALASKA

Before Commissioners: Robert M. Pickett, Chairman
Stephen McAlpine
T.W. Patch
Norman Rokeberg
Janis W. Wilson

REGULATORY COMMISSION OF ALASKA
701 West Eighth Avenue, Suite 300
Anchorage, Alaska

PUBLIC MEETING

April 8, 2015
9:00 a.m.

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P R O C E E D I N G S

(On record - 9:01 a.m.)

CHAIRMAN PICKETT: Good morning. This is a public meeting of the Regulatory Commission of Alaska. It is Wednesday, April the 8th, 2015 at 9:01 a.m.

With me on the dais are Commissioners T.W. Patch, Commissioner Stephen McAlpine, and Commissioner Janis Wilson, Commissioner Rokeberg will be joining us, and I'm Chairman Pickett of the Commission.

Agenda item No. 1 is public participation. Are there any members of the Anchorage audience who would care to address the Commission this morning?

Seeing none, we will move to anyone on line. Does anyone on line care to address the Commission? Hearing none, we will close agenda item No. 1, and move on to item No. 2: R-15-to be determined, Possible Regulation Changes in 3 AAC 52 Addressing Subscriber Directories.

Commissioner Patch, please take it.

through April the 30th, not mandatory but a lot of things were put on the table and I think it would be good to have the opportunity for all of the participants to comment if they choose to.

So I will make that in the form of a motion. Is there a second?

COMMISSIONER PATCH: Second.

CHAIRMAN PICKETT: Discussion? Seeing none, we'll move onto the vote.

All those in favor say aye.

COMMISSIONERS: Aye.

CHAIRMAN PICKETT: And, Judge Lawrence, you will have that order going out shortly and at the public meeting on the 22nd we will have the summarization of the initial comments in a matrix type of form.

So with that I'm pleased to have Dr. Anthony Scott from the Alaska Center for Energy and Power with us. He has been working with the Commission since August and it's an appropriate time for him to give a bit of an overview as to what's been happening and we are about to head into a very intense series of public meetings

beginning with the 22nd of April we will be having public meetings on this matter every week, whether it's a regularly scheduled public meeting or a special one. We'll keep you posted as to the nature of the topics. It will be somewhat evolving.

But with that, Anthony, it's all yours.

MR. SCOTT: Thank you, Mr. Chairman. So I was asked by the Commission to work with them in a little bit of an unusual capacity, at least in terms of how consultants are often -- have been engaged in this broader discussion about Railbelt organization and potential reform. More typically consultants are asked to come in and to generate a report, maybe with some recommendations, but it's fairly hands off. The report, in general, doesn't go to a decision-making body.

In this case you guys are a decision-making body and, indeed, you've been asked to make a decision. A year ago -- just about -- the Legislature in a single line charged the Commission with providing a recommendation, which is a decision, as to

whether creating independent system operator similar structure for electric utilities in the Railbelt area is the best option for effective and efficient electrical transmission. It's your recommendation, it's not mine.

So because of that it doesn't really make any sense for us to sort of run away and work on some sort of opus for a long time and then say, Here, eat this. What do you think?

So the process has been somewhat more iterative than that. It's much more of a technical staff, kind of, engagement. There are, indeed, work streams that are beginning to emerge from this process and those will all be public and many of those will be rolled out in pieces as we move forward.

I will say this is probably the single hardest project I've ever worked on because it is so inchoate. There are so many potential directions, such a diverse set of interests, very different views. What's been particularly hard is that there is an

enormous amount of work that has already gone on on this subject in one way, shape, or form. So generating anything that is new or novel has been a bit of a head scratcher, especially given the limited resources that were made available by the Legislature for this purpose.

Having said all that, basically, there are roughly five work streams or work packages that we've been asked, working with the Chairman, to generate.

The first is a review of previous efforts or studies at reform in the Railbelt going back to, say, 1998 or so. So we've -- again, we've been at this for a while, more than 15 years.

Another would -- involves characterizing, in a completely generic sense, what an efficient Railbelt electricity system would look like.

Assessing whether there are reasons to think that the existing system could be more efficient, outlining some policy options for achieving efficiency.

And then doing a somewhat deeper

dive into certain models that are used Outside, that is in the Lower 48, for capturing efficiencies and whether those, indeed, are locally applicable and how so -- or indeed whether.

So there's a long list of things -- of work that has been historically done and I throw this list up there and don't want to get into the details of what each one covers. That will follow.

But it's actually a quite impressive body of work. The more I've looked at it and reviewed it and tried to understand it the more impressed I am, really, with the quality of the work that's been done today.

(Commissioner Rokeberg joins the meeting.)

There's several things really, I think, to note about the work that's been done today. Although assumptions evolve as local economic conditions evolve, demand changes. There are new facts on the ground in terms of what the generation stock are. There are new facts on the ground in terms of

what the contractual relationships are. There are new facts on the ground in terms of what the perceived requirements of the day are.

In general -- pulling back just a little bit -- the studies provide a very good map of a number -- probably, essentially all of really the key variables that we would want to think about. They look at different ways of institutionally being organized within the Railbelt, within and among the utilities. They look at a wide diversity of assumptions around fuel price contracts. They look at diversity -- I mean, when you pull back and sort of -- and I don't think this was necessarily always done by design, but across the studies you see this, they offer diversity of assumptions around transmission infrastructure, around generation infrastructure, financing, future demand paths in terms of reliance on fuels, renewables, that sort of thing. So there's a lot of work that's been done. It spans a wide variety of relevant variables.

It's interesting that, to a

1 considerable degree, the reports in the main
2 have been done without an obvious decision
3 path in mind. In some cases the reports have
4 been done for bodies that have no
5 decision-making authority, no ability to sort
6 of implement any of it.
7 So the other thing, of course,
8 that's remarkable is that we haven't
9 necessarily had a lot of policy formations
10 saying that this is -- this, something new,
11 is what should happen. In general, for the
12 most part, overwhelmingly -- maybe entirely
13 -- the utilities have made the decisions
14 about how they will be organized on their
15 own. And that continues throughout the
16 evolution, you know, since -- certainly since
17 '98, '96 to the present day.
18 And that's not necessarily a bad
19 thing, it's just a description of where we
20 are. The utilities have been the leaders in
21 designing and deciding what will happen and
22 where we are now is a function of that.
23 So why does this issue around
24 efficiency, in one shape or other, not go
25 away? Well, this is speculation -- but this

is my speculation -- I get to talk, so I'll tell you what I think -- it's a small grid. It's -- the total demand within the Railbelt is cumulatively, collectively, smaller than most small utilities in the Lower 48. And yet we have six separate utilities. This is an industry which is marked by economies of scale -- generally understood as being marked by economies of scale. The electric utility industry is the most capital intensive industry that there is. It requires more capital per unit of revenue than any other industry that -- at least that I'm aware of -- that certainly was true last time I looked at it, which I admit was a while ago. It's been ten years.

We also have a certain amount of ideological winds in fashion that happen. You know, there's developments Outside and then we look at it, doesn't make sense for us to do something, and we have political pushes and pulls around various interests.

I think the issue doesn't go away also though because of state involvement in the grid. So as a public policy discussion

it doesn't go away because the state has, from time to time, injected money into the Railbelt, and from time to time the Railbelt utilities have asked the Legislature for infusions of capital. Not passing judgment on that, but it certainly makes sense that if you have private entities asking for public dollars it would be unsurprising then that there would be public discussion about whether the dollars were being most effectively and efficiently being put to use.

And then lastly, I haven't done a comparative assessment of this by any means, but my casual observation as non-practitioner and an outsider is that there's a fair amount of inter-utility litigation and strife. So if there was a way of reducing that, potentially through a new organization of some sort, wouldn't that be nice? So, I think -- you know, again, that's my speculation as to maybe why the issues don't go away.

Right now we've got a constellation of a certain set of issues, which you all know much more about and are

dealing with than I. But for the last -- the Railbelt used to be marked -- at least Cook Inlet was -- by having very inexpensive gas compared to the Lower 48. That's no longer the case. We now have the highest natural gas prices in the country. Considerably so. And we -- this is a function of the roll off of legacy and expensive gas contracts which were tied to very large fines, which, you know, eventually we've worked off, and so the market is much more in balance between supply and demand. It's a very slow market. So natural gas prices have risen and they've created concern around future availability and so on.

The breakup of the Tri-Partite agreement has obviously caused a lot of change. We're moving from three control areas to five and that has also led to -- that has contributed to -- I should say -- a bunch of new generation additions. The new capital additions are also, obviously a function of just retirements and replacements. But MEA for the first time has added a lot of plant. Chugach and ML&P have

done -- ML&P on their own is pursuing 2A. Homer's added a fair amount of generation and GVEA expect Healy 2 to come on line. So there's a lot of new stuff that we're dealing with or will soon and raises questions about how most efficiently to manage and deploy it.

And then finally there's the State of Alaska fiscal position. We have been for some time, but we didn't know it, we're poor. We haven't been acting like it but we've -- but we need to now given current oil prices. So the dollars available for capital expenditures have shrunk very substantially and I think that, just in general, creates an interest in seeing whether we might be able to be more efficient.

So I won't get into a discussion of what marks an economically efficient Railbelt system much today, but there aren't very many elements really. I mean, it's really fairly simple.

In terms of the stuff that you have, the existing kit, the existing generation assets, hydrocarbon contracts,

markets, and transmission assets, using those assets most efficiently to generate the KWh that are required by consumers is basically known as economic dispatch. Now, you can have economic dispatch Railbelt-wide or you can have economic dispatch utility by utility.

If you have -- and each of the utilities, I assume, and have good reason to think, are indeed performing economic dispatch within their own service territories. But if you take advantage of the opportunities afforded by transmission then you reduce some constraints and potentially you can dispatch units with savings Railbelt-wide.

Now, how those savings might be distributed is potentially -- it's not always obvious how that's going to happen, and solving that problem is one of the questions of institutional innovation that is served before you.

I would note in the very first study that I just listed Black & Veatch in 1998 when they were looking at Railbelt-wide

economic dispatch, they note -- at the very end -- there's a sentence at the conclusion of that report that said that the subject of the division of savings was a contentious one among the parties that they've been working with. It's an important question, not an obvious issue how those savings get split such that people want to pursue them.

There's also, though, an issue of figuring out what, in terms of efficiency, if our lens as the Railbelt as a whole figuring out what is most efficient to build to meet growth and load, and that involves planning. If parties are planning jointly, together, and fully can share in the benefits of what might be constructed, you can defer and avoid building -- well, you can build less. You can reduce the amount of generation assets that you have to build.

And so there are opportunities there for savings. Again, going back to the very first study on your list Black & Veatch looked at that question. They made forecasts of demand and noted the reserve margins that were required to be held and compared the

difference between separate planning of each of the utilities for new generation and joint planning and found that the benefits on a net present value basis of jointly planning generation additions over the 20-year period were about as large as the fuel savings benefits. In certain circumstances they could be considerably greater.

So a third mark, I think, of an efficient system is to have a business case for building what it is that you need to build at the lowest cost possible. And that means, in the case of generation that's particularly complicated. If you've got generation assets that will provide service to more than one service territory, it pulls to the front how the benefits and costs of that asset will be shared. It's notable, I think, that the biggest transmission asset -- or the -- well, I shouldn't say biggest, but the Intertie between north and south of the range, which has led to such benefit, both for Golden Valley customers, Fairbanks customers, as well as the generating utilities south of the range was built by the

state. The business model in that case was the state built it.

And that -- that's important. I mean, essentially all of the utilities have shared in the benefits of that piece of hardware. The problem didn't need to get addressed because the State solved it. They solved it, not for reasons because well, these utilities can't figure this out -- they solved it because they were anticipating the (indiscernible) in the dam, which didn't happen. So it was a prebuild to take advantage of that construction project, which obviously hasn't happened. But it has yielded enormous benefits over time.

The costs of financing are also relevant to the question of cost of construction.

Service reliability is also, I think, a necessary aspect or component of thinking through what marks an efficient system. I say that because service reliability is a constraint on how the system is operated. The need to maintain service reliability affects what it is you that you

run and how you can run it. As well it is a critical social good. It is a critical aspect of what the system is meant to deliver. So you can't sort of abstract from that question.

Finally, nonbilled values, I think, are part of what constitutes an economically efficient system. What do I mean?

The first three elements of economically efficient system really go to how do you minimize costs while providing demand to all of your customers. Cost minimization question is really simple, right? I mean, for an -- it's just: How do you minimize costs?

But nonbilled values is extremely important because care, not only -- or at least many people care, not only about having the lights turn on when they flip their switch. In some cases nonbilled values incorporate things like green energy. You see that through renewable portfolio standards in other jurisdictions.

But nonbilled values also go,

importantly, I think, to -- I mean, we have -- in the main we have consumer-owned utilities here and some of the values that people have as consumer-owned utilities is that they are or desire to be independent. That is I am in control, to a considerable degree, of my destiny. I can build what I need to and meet my customers needs. That is not surprisingly an important Alaskan value beyond the electricity context.

You know, values are what they are, right? I mean, you might like different cereals than I do, but who's to dispute them. It's important to pay attention to -- because I think it has direct bearing on whether the most -- on what -- what the most efficient Railbelt system might look like. And it's perfectly valid.

So reasons for thinking that the Railbelt is less than efficient. This is one of the things we're supposed to assess as part of this. I mean, is there a problem? Really, that's the question, right? Is there a problem?

Well, a problem compared to what?

You have to recap your goals, right, and I've listed them here. Comparison -- I mean, whether there's a problem is you have to compare it something. Compared to what? What could you achieve?

The problem that we have in answering this question of less than efficient is you need a counterfactual. The data are only what has happened or is happening now. To say that you could be more efficient means you have to be able to say if you did something differently what would the results be. That forces a reliance on models.

So all of the previous studies -- or most of the previous studies engaged in modeling exercises. From a public policy perspective that creates enormous difficulty for you, because everybody who comes in front of you who doesn't like the answer is in a very good position, because they have deep expertise to say, You assumed the wrong things. The logic of the model is incorrect and the results aren't like that.

I mean, that's a profoundly

difficult, problematic aspect of what you're faced with; because models aren't reality. Models always involve simplifications. The simplifications are designed to highlight, hopefully, certain dynamics. Hopefully the models teach you something but they are not reality.

I say this as someone who is a very chastened modeler. I used to -- when you build models there is a tendency, after a while, to believe that your models are true, because you work on them so hard and so you tend to start thinking that they're concrete that they represent something real and that's just not the case.

Models are always deep simplifications of reality and they're not real. They're useful. They're tools. They're useful, but because they're not real, people with deep expertise are always in a very good position to say that your model is not appropriate or not right or what have you. And there is no easy way to cut through that. It's just recognize that's the situation that you're in. It's something

that I've been keenly aware of as I try to approach this because I have so much less expertise than the relevant players who are interested in and potentially affected by this discussion.

So one of the things that we are doing then in reviewing the studies is describing the different modeling frameworks and the different kinds of assumptions and trying to pull out and develop how the modeling, set up, logic, and assumptions drives particular results. And I think that will be useful for you to understand because, again, there's been a fair amount of work that's been done. An awful lot of work that's been done. Much more money spent than you guys are spending on us -- or the Legislature is spending on us.

We have done -- we have engaged folks to do some modeling specific to this project. The modeling that we've done has piggybacked on and followed up on the modeling work that was done for the Alaska Energy Authority by EPS and, in particular, by a subcontractor for EPS, Slater

Consulting, who's looked at the question of economic dispatch in a Railbelt which has potentially much more robust transmission.

So the Railbelt-wide economic dispatch question what the savings and benefits associated with that are, both if you were to pursue it now without transmission upgrades, and if you were to pursue it with transmission upgrades is a function, obviously, of different assumptions. You roll out different assumptions around fuel prices and so when you get or demand you get very different results.

But broadly speaking we've tried to piggyback off that work and develop somewhat different assumptions to look at potential, overall costs borne by ratepayers in a particular year in question. We do that by looking at the benefits of savings associated with the economic dispatch less the costs, the annual carrying costs that ratepayers would have to bear of new transmission, as well as annual carrying cost of dispatch organization.

So if you're going to have economic dispatch you're going to have some organizational costs associated with that. They can be greater or smaller depending upon the nature of the organization. We looked at that question as well in terms of relying on analogs Outside to get a sense of how important that is.

We -- there should be, potentially, or could be utility personnel costs that show up in terms of not need quite so many folks. If you've got centralized dispatch that you don't have five different load balancing centers. We're ignoring that question for now. It's pretty speculative and it's -- there certainly are contentions among some of the parties that there will not be material utility personnel savings.

And I think that's a perfectly reasonable assumption to make. I can't speak to one way or the other. But this is a framework that we look at in a fair amount of modeling that we are -- will be rolling out in future weeks.

This modeling framework here

unfortunately captures very little of the benefits that might be afforded by a new utility framework. If we had more robust transmission, if we had centralized dispatch, if we had joint planning, dynamically decisions about what would get built and how it would be operated would be different. And the benefits of those might indeed be considerably greater over time than the economic dispatch benefits. That's not something that we have budget or scope to get into.

Those sorts of questions around savings have been looked at by other studies and we'll highlight them for you just to indicate the dynamics in play. They're not -- we don't -- we can't give you predictions, and, indeed, some of the savings that might have been realized through joint planning, in terms of why that's constructed, some of those opportunities are no longer available. I mean, the horse has left the barn, given the very considerable commitments that have been and are being made.

Benefits of improved reliability

is something that we are going to wave our hands at but not be able to deeply get into.

The ability to incorporate more renewables and potentially competitive wholesale power is something which is a nonbilled value. In some quarters it's ideologically extremely important. That would probably be -- opportunities for that would probably be substantially improved under certain organizations. And none of these benefits can be captured by the static modeling that we do.

We are -- many of these benefits are not easily captured anyway. We are unfortunately like the drunk who's looking for his keys. You know, he hangs out under the light post and -- Did you lose your keys here?

No.

Well, why are you looking here?

It's because where the light's good.

You know -- so that's what we do.

There are certain economic risks associated with any transition. Loss of

local control is substantial risk and potentially substantial set of costs.

Indeed the costs from economic dispatch and building out, saying, new transmission to better take advantage of the potentiality for that may not show up. If population declines in Alaska, if hydrocarbon prices change, benefits may not show up. It's also the case that benefits might show up, but they may not be captured by my customers. And if they're not captured by my customers I might not be interested in proceeding with a reorganization of how we work. So just the fact that the Railbelt as a whole might be somewhat better off, I don't care. And if I can block that I may try to. In fact, it would be reasonable for me to try to.

Net benefits may exist but the other guys might get more of them. This is a similarly difficult and profound problem. The argument over who gets what is big and it's especially problematic because who gets what is a function of -- the splitting of the pie will be -- will involve risks. I give up

something for certain on the hope that I get a share of benefits in the future. There's not a mathematical problem to address any of that. So one of the things that we will do -- or we have done in our modeling -- is try to highlight the particular nature of these kinds of problems.

So we explore some policy options to solving the generic descriptions of efficiency. One of the things that took me a while -- and I'd like to sort of share with you all and I think the public as a whole should be aware -- there's been an awful lot of institution invasion in terms of how public utilities are organized in the Lower 48. Those development and organizations have been driven by events and imperatives and prerogatives that don't necessarily have a good fit up here.

In particular, since at least -- well, really since PURPA in the late '80s, and since the early '90s with the Energy Policy Act in '92, and subsequent FERC orders in the '90s; there's been a profound push towards making the wholesale market in

electricity competitive. The idea is, you know, maybe given the size of the grid in the Lower 48, given its interconnected nature, given the diversity of players, given the march of technology, the advances associated with economies of scale in terms of getting bigger and bigger for generation assets appear maybe to have been largely exhausted. Power can be provided competitively, which is to say the cost of power maybe is best determined through market forces rather than through rate base rate of return utility regulation, which is what you guys basically are involved in here.

There are good reasons to think -- and some of these studies wrestle with this and come to conclusions with it, which I share -- actually, that the utility, the Railbelt utility is not a good fit for competitive wholesale markets where prices are determined on the basis of offers and bids for electricity in real time or even under a long-term contract, but instead are -- I mean, where rather than on the basis of cost.

We do not -- we have market concentration here. We have, at most, five sellers and those sellers have considerable market power at least in terms of the generation assets they should.

Our hydrocarbon markets are also sticky and small. We do not have a robust grid. And, finally, none of our market participants are for profit entities. And so the normal standard market assumptions around competitive transactions don't necessarily (indiscernible).

So the focus for us really needs to me on the functions that need to be performed by various institutions how to get efficiency rather than simply adopting wholesale options that have been created Outside.

In terms of the questions that you guys have to address -- I mean, the critical question is: Do the perceived benefits either statically or dynamically outweigh the risks of doing something new? It's not an obvious answer, especially once an on build value is brought into account.

And if something new, then what? What are you trying to achieve? What things look like if you are very interested in having competitive wholesale entry of IPPs into the market is quite different than if you don't. What you're trying to achieve if you've got renewable portfolio standards is quite different than if you don't.

Who controls and who decides become critical issues. We do something of -- I think in terms of broad choices of something new, at least as I see it you have a question of well, do you want to have a mandatory reliability organization in the Railbelt or not. And there are good reasons for going either way. But that is a discrete question and the answer to that question might be yes, for example; and that could be the end of it.

You could also proceed by saying, well, let's have a Transco which is to say a single or unifying entity that owns transmission assets and has a business case for financing and constructing new transmission assets if those make sense. And

then one leaves dispatch questions up to the participants and if they do not ring out the efficiency opportunities then you might be able to come back and subsequently do something about that in terms of creating a tight pool or some other unified dispatch mechanism.

You could have a Transco without having mandatory reliability standards as administered by the Commission.

You could also start with mandatory unified dispatch and have a Transco follow. So these are all separable. And what it raises is if you're going to do something do you want to do it all at once? Do you try to swallow the elephant or maybe do you do it starting with one or two of these functions. And having the other follow along leaving options open.

I would say you're not the only actor here, obviously. There are nonprofit utility boards or in the case of ML&P we've got a Muni board. This is where local values are expressed in terms of what people want. They're critical policy-making bodies

obviously.

The utility management is where much of the technical expertise lies. When I spoke to the difficulties of modeling, I was addressing this in part. There will always be an important gulf between what they know and what the rest of us know.

The Regulatory Commission has deep regulatory expertise, uncertain authority in terms of its ability to push any of this forward. You've raised that and asked for comments on that. I think that's extremely helpful. And it's -- even if you do have authority it's uncertain what your policy mandate is.

And then the State Legislature, I would argue probably has the least expertise. I hope I don't offend anybody. Potentially great authority, somewhat diminished carrot-offering capacity today, but there's still enormous things that they can do to grease the skids.

This last set of -- this last slide is really quite important. What marks an equitable Railbelt system? We weren't

asked to address this, the legislature didn't ask you to address it, but it's -- and it's really outside of our scope, but it's critical because given the policy actors that you have, you have a transactional question of how you get from here, where we are now to there if you want to do anything. And there is, at least, a possibility that any one of the Railbelt utilities or parties feel that they're overly aggrieved that our ability to make progress will be stimied given the political dynamics and how things work -- and courts. I mean, when I first started having conversations with the Chairman, I think I admitted what this process really needs is a very good facilitator because at some level none of the work that we can provide or summarize or try to digest, particularly matters if it can be blocked by somebody who doesn't like the answer.

Now, whether that's the political reality, whether a party or two parties together can block something that they don't like is an empirical question and we'll find out, but it certainly will be greatly eased

if everybody, kind of can more or less hold hands, even if they don't like the person very much who they're sitting next to and is willing to step off the curb together.

And so particular attention really needs to be placed on governance questions and that involves not just what the end result is in terms of who decides but also governance in the process. The ability of any one party to be able -- their -- their willingness to launch into the process will probably be affected by their perception as to whether they will be able to reasonably shape it to protect what they see as their interests.

And I'm sorry I took so much time and I'm done.

CHAIRMAN PICKETT: Thank you. Let the record reflect that Commissioner Rokeberg joined us early in Dr. Scott's presentation.

At this point I would like to turn to the Commissioners for any comments or questions they may have. We will be seeing a lot of you over the course of April and May. The public meetings that we do have scheduled

and the special public meetings will be getting into various elements on a fairly granular basis. This will all feed into the Commission's ultimate determination. We want it to be a very open and transparent public process so you can, at least, see the record that we're relying upon for the decision that we will be making.

So with that thank you very much. We will close this agenda item No. 3, and you will be expecting Order No. 2 in I-15-001 from Judge Lawrence in the next couple of days for the reply comments. So thank you in advance for your participation.

That leads us to agenda No. 4, other business. Is there any other business that needs to come before the Commission this morning? Seeing none, we will close that agenda item.

No. 5 is executive session. Does the Attorney General have need for an executive session?

MR. GOERING: No, we do not.

CHAIRMAN PICKETT: Agenda item No. 5 is closed.

I-15-001
Alaska Railbelt Electricity System

Overview of Work for the Regulatory Commission of Alaska

4/8/2015

ACEP
Alaska Center for Energy and Power

Legislative Charge

RCA should recommend:

Whether creating an independent system operator or similar structure for electric utilities in the Railbelt area is the best option for effective and efficient electrical transmission.

Overview of ACEP's Engagement

- Review previous efforts at or studies of reform
- Generically characterize what would an efficient Railbelt electricity system look like
- Assess whether there are reasons to think that the existing system could be more efficient
- Outline policy options for achieving efficiency
- Review ISO/Transco models pursued outside for local applicability

Past Studies Addressing 'Efficiency'

- 1998 Power Pool/Central Dispatch Study (B&V for APUC)
- 1999 Electric Utility Restructuring study (CH2M Hill for APUC and Legislature)
- 2003 Alaska Energy Policy Task Force (for Leg.)
- 2007 Cost Savings from Alternative Combination of ML&P and CEA (Navigant for those utilities)
- 2008 Railbelt Electrical Grid Authority (B&V for AEA)
- 2010 Railbelt Integrated Resources Plan (B&V for AEA)
- 2013 Railbelt Transmission Plan (EPS for AEA)

Why Does the Issue Not Go Away? (Partial list)

- Small grid with multiple parties in industry generally marked by economies of scale
- Ideological winds and fashions
- Periodic injections of State investment
- Periodic requests for more state investment
- Inter-utility litigation and strife

Issues of the Day…

- Roll-off of legacy, inexpensive gas contracts
- Breakup of the Tri-Partite Agreement
- Five control areas, from three
- Substantial generation additions, new or on horizon
  - MEA: Eklutna Generating Station
  - CEA & ML&P: SPP
  - ML&P: Plant 2A
  - HEA: Soldatna and Nikiski
  - GVEA: Healy 2
- SOA's fiscal position

What Marks An Economically Efficient Railbelt System?

- Using existing assets at least operational cost ("Economic Dispatch")
- Stakeholder-relevant public information on the least cost new generation & transmission assets needed to meet future system needs ("Planning")
- A commercially relevant business model to finance and build what is planned, at least cost ("Construction")
- Service reliability
- Non-billed values

Reasons for Thinking the Railbelt Is Less then Efficient?

- Recap goals:
  - Economic dispatch
  - Generation and transmission planning and construction
  - Service reliability
  - Non-billed values
- Comparison needed
  - Data alone rarely determinative
  - Necessary reliance on models

One model: EPS Static Economics

Annual, future year net "benefit" =

(*Economic dispatch* +
Utility personnel cost reductions) –

(*New transmission* +
Dispatch organization costs)

Economic Opportunities

<u>New *options* more than new *results*</u>

- Joint planning for new transmission
- Business model for new transmission
- Economies of scale for new generation
- Joint planning to “right size” capacity adds
- Improved reliability
- Ability to incorporate IPP’s and renewables
- Reduced litigation (?)

Economic Risks

- Loss of local control
- Costs may outweigh benefits
- Net benefits may exist, but not be captured by my customers
- Net benefits may exist, but the other guy may get more of them

Policy Options (A Caveat): Railbelt is not like lower-48

- Lower-48 developments driven by desire to make wholesale competition work
  - Lots of institutional innovation and acronyms
- Unlikely that deregulated wholesale pricing would work in Alaska
- Focus on functions, rather than definitions

Policy Options

- Status quo, or something new?
- If something new, what?
  - Mandatory Reliability Organization?
  - Transco?
  - Mandatory unified dispatch (ISO/RTO vs tight pool)?
- If something new, then gradually or all at once?
- If something new, then how (process)?

Policy Actors

- Non-profit Utility boards
  - Where Local Values are Expressed
- Utility management:
  - Where Much of the Technical Expertise Lies
- RCA
  - With regulatory expertise but uncertain authority or policy mandate
- State Legislature
  - Least expertise, potentially much authority, diminished carrot-offering capacity

What Marks an Equitable Railbelt System?

- Answer lies outside ACEPS's scope
- A Critical Transactional Question:
  - Getting from "here" to "there" may require that no party is overly aggrieved
- Particular relevance on "governance" in the innovation process, as well as for end-point institutions

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STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners: Robert M. Pickett, Chairman
Stephen McAlpine
T. W. Patch
Norman Rokeberg
Janis W. Wilson

REGULATORY COMMISSION OF ALASKA
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501

PUBLIC MEETING
April 22, 2015
9:00 a.m.

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P R O C E E D I N G S

(On record - 9:04 a.m.)

CHAIRMAN PICKETT: Good morning. This is a public meeting of the Regulatory Commission of Alaska. It is Wednesday, April 22nd, 2015, approximately 9:04 a.m. With me on the dais are Commissioners T. W. Patch, Commissioner Janis Wilson, and Commissioner Stephen McAlpine. We're anticipating Commissioner Rokeberg to join us shortly.

Agenda item number one is public participation. Are there any members of the Anchorage audience who would care to address the Commission this morning?

Please come forward to a mic, identify yourself for the record, and keep your comments to not more than five minutes. There's a button to push and you get a green light.

MS. SCHMIDT: All right. Thank you. Good morning. My name is Karen Schmidt. I'm an associate attorney at Bessenyey & Van Tuyn. And we represent Mike Craft, managing partner of Alaska Environmental Power. My testimony today is on behalf of Mike who could not make today's public meeting but wanted to make sure that the

RCA understands his concerns, particularly with respect to matter I-15-001. Mike and Alaska Environmental Power are tracking RCA matters related to transmission issues and would like to continue to be informed and participate in all future meetings on this issue as the RCA moves forward. Regarding the matter before you today, I-15-001, Mike wanted to highlight three main concerns.

First, we are concerned that the new system operator structure will perpetuate the same problems currently experienced by independent power producers, namely that the proposal continues to separate transmission assets from generation assets. IPP's need open and fair access to make sure they have a shot at being able to share in the market. For example, just this morning I read a Juneau Empire article about IPP projects being considered in the Legislature.

IPP's need to be able to trust that they will get a level playing field in all areas, and we trust that this will include the RCA well into the future. IPP's have been facing an uphill battle in the state of Alaska and that needs to stop.

Second, we are concerned that the RCA matter

is only including the Railbelt grid and is ignoring the larger statewide policy including potential interconnection with Canada and how this would be addressed with an ISO.

And, finally, we reiterate that the RCA should not codify a distinction between firm and non-firm power, that the distinction is a fiction. It is not fair to IPP's to falsely and arbitrarily classify power producers as either firm or non-firm when IPP's are equally reliable and efficient.

Thank you for the opportunity to speak. Alaska Environmental Power hopes to work with the RCA in the future on this issue.

CHAIRMAN PICKETT: Thank you.

Is there anyone else in the Anchorage audience who would care to address the Commission? Is there anyone online who would care to offer any comments to the Commission this morning?

MR. MITCHELL: Mr. Chairman?

CHAIRMAN PICKETT: Yes. Please identify yourself for the record.

MR. MITCHELL: Mr. Chairman, this is Duff Mitchell. I'm the managing director for Juneau Hydropower, Inc. We are the developer of a

FERC project located in southeast Alaska, Sweetheart Lake hydroelectric facility.

CHAIRMAN PICKETT: Please proceed and try to keep your comments to no more than five minutes, Mr. Mitchell.

MR. MITCHELL: Yes, sir. Thank you.

My addressing today to the Commissioners is RCA overreach. I would like to read you an e-mail. I wish Commissioner Rokeberg was present. This is an e-mail from him.

From Rokeberg, Norman, RCA; Thursday, April, 16, 2015, 11:47 a.m.; to Senators Kelly, MacKinnon, Micciche, Bishop, Dunleavy, Hoffman, Olson, and then a cc to himself; Subject, HB150 SB50, stop Christmas treeing.

My personal recommendation is the removal of all additional ADA project bonds. Without solid legislative hearings, mischief happens. While the two Railbelt projects have merit, the Railbelt system reliability in Eagle River would be better served by investment in the native Fossil Creek substation rather than an upgrade to MEA's native load north of Eklutna hydro.

The Sweetheart deal -- in exclamation

marks -- is troubling as it may increase retail rates due to an unneeded capacity increase without any offset in federal greenhouse gas emissions under the CPP. These are my opinions, not those of the RCA.

(Commissioner Rokeberg joins dais.)

How is it sending this sort of e-mail from an Alaska gov e-mail account and pretending it does not implicate and carry the weight of this office or as a Commissioner of the RCA? This is troubling.

Further, on the ADA -- on the APA on -- I'm sorry -- the RCA web site under structure it says, the Chairman is ultimately responsible for the timeliness of the Commission's adjudication process, meeting statutory time limits, and serving as the Commission's liaison to the legislative and executive branches of the government.

Also, under 3 AAC 48.170, ethical standards and violations, any person transacting business with the Commission shall maintain at all times the respect due the Comission, its presiding officers, legal counsel, and its staff and shall never knowingly by artifice, statement, or silence

lead to allow them to believe in a false factual or legal proposition relative to the discharge of their responsibilities. And it says, members of a legal, accounting, financial, engineering profession shall also comply with the ethical standards of their respective professions.

You know, I'm sorry to bring this forward, but we had an authorization. Purely a bond authorization. In no way, shape, or form does that give you a loan. It's just merely the opportunity to apply to another State agency, ADA loan programs. And House Bill 105 passed the House 37 to 2. We had no indication of any opposition.

And then, amazingly, this letter shows up and all other projects were stripped out of the Senate. This is lobbying. This is knowingly and willful, and either it's negligence or misconduct. But because Commissioner Rokeberg is a former state representative, he carries a lot of weight.

As to the merits of his troubling statement with the Sweetheart deal, my company and our people have worked diligently for six years bringing not only low-cost power to Juneau but the needed capacity for energy security for my city.

We can go through a whole gamut of reasons why we reduce the cost of power to our community. However, I don't think that's the time nor the place with only five minutes. I just ask for the Commission's consideration in this matter. I think it's wrong. I think it affects the integrity and credibility. And I would just like to see it fixed. Thank you.

CHAIRMAN PICKETT: Thank you for your comments, Mr. Mitchell. The e-mail you referred to that I've become aware of now is in no way, shape, or form the position of the Regulatory Commission of Alaska with specific pieces of legislation. The only way that the Commission takes a position is at a public meeting with an open vote from this dais. And in that matter you referred to, that has not occurred and that is not on our table at this point.

Because of the nature of this comment, I'm going to offer Commissioner Rokeberg an opportunity to say something. But, again, that e-mail was his reflection. I subscribe, personally, to the fact that we need to keep our mouths shut on legislation unless we're specifically asked by a bill sponsor or the

administration, and then there is a very structured process to take a position. So with that I will be still.

Commissioner Rokeberg, did you want to say anything?

COMMISSIONER ROKEBERG: Thank you, Chairman. Just to reiterate the fact that in the nature of the e-mail, which I sent to the members of the Senate finance committee only, I indicated that these were my personal opinions and not the opinions of the Commission. I was exercising my First Amendment rights. And what I said was that when you add additional items to bills, that is to say Christmas tree them, they tend to create mischief.

I was a legislator for 12 years. I'm very familiar with the process, and that was my point. As a matter of fact, the point should be made that the -- my objection was to all the projects, not one in particular; or I wasn't intending to single out anything. The -- the problem becomes when you start at the end of the session creating bargaining chips for no good reason; mischief occurs.

And with that -- I would say one thing, too,

any intimations that I breached anything that was unethical or inappropriate in exercising my First Amendment rights, I take great, strong umbrage to. I've lived in this state for 65 years. My reputation in the business community and the legislative community speaks for itself. Thank you.

CHAIRMAN PICKETT: Thank you, Commissioner Rokeberg.

Is there anyone else online who would care to address the Commission this morning?

REPRESENTATIVE WILSON: Yes, sir. Yes, Mr. Chairman.

CHAIRMAN PICKETT: Please identify yourself for the record and keep your comments less than five minutes.

REPRESENTATIVE WILSON: Absolutely. This is Representative Tammie Wilson. I represent North Pole. And I just have, really, one question just based on the conversation and e-mail that I received last night. I guess I would just like to -- and it doesn't have to be discussed today. But is there a procedure for a Commissioner to use the RCA e-mail versus their own?

I know that it's very hard sometimes when you

are playing more than one role to make sure that people understand which one you're addressing. But the only concern I had when the e-mail was sent to me last night was that this particular e-mail showed it came from the RCA e-mail versus a personal e-mail. So I just didn't know whether you had a procedure in place just so there are no misunderstandings. Thank you very much for the opportunity.

CHAIRMAN PICKETT: I think that's a very good point that you bring up, Representative Wilson. And we will have a policy to that affect if it's not on the books already. And I will have the AG look into that further. Thank you.

REPRESENTATIVE WILSON: Thank you.

CHAIRMAN PICKETT: Is there anyone else online who would care to address the Commission? Is there anyone else in the Anchorage audience -- sorry for the feedback. The mic seems to be a little bit hot.

Is there anyone else in the Anchorage audience who would care to address the Commission? Seeing none, we will close out agenda item number one, public presentation.

Agenda item number two is a presentation by

We're back on the record. It's approximately 9:40 a.m. And we're on agenda item number three, I-15-001 in the matter of the evaluation of the operation and regulation of the Alaska Railbelt electric transmission system.

For this agenda item we are going to actually have three separate presentations. And we will start with one that does sort of a high-level overview of the comments received to date based on our Order 1 in this docket. I will turn it over to Judge David Lawrence and have you do the appropriate introduction for your part of the presentation.

ALJ LAWRENCE: Thank you, Chairman Pickett. And good morning, Commissioners. I'm Judge David Lawrence. I was assigned to preside over the I docket, which in some ways is a companion to the assignment you received from the Legislature related to the -- whether an ISO is a good idea. And so they're kind of moving in parallel. And I'll try to keep them separate, but they're kind of joined at the hip.

Not long ago in response to your Order 1 you received 16 sets of comments. In fact, I think they're listed on the screen here --

CHAIRMAN PICKETT: Before you go too much farther, now, who is that sitting next to you?

MS. JENSEN: Oh, my name is Anne Marie Jensen, and I'm the process coordinator here at the Regulatory Commission. And I ask everybody bear with me because I just had a crash course in PowerPoint. This is my first time up here. So if I click too fast, my apologies. I'll wheel it back.

CHAIRMAN PICKETT: And if we have a system crash, we have James Keen in the back for technical assistance.

MS. JENSEN: Yes. Thank you, James.

CHAIRMAN PICKETT: So please proceed.

ALJ LAWRENCE: Thank you. I should say that I know you Commissioners have been reading these comments with great interest. And I think the people that put them together put a lot of time and effort into them. And I want to thank them -- and I imagine Commissioners do, as well -- for the research and the thought that went into them. They should know that they are being

studied and summarized.

Anne Marie put in significant time helping the Commission by slicing and dicing them in various ways to summarize them. From a certain level, I put in a little analysis I shared with you yesterday.

If you could flip to the next slide. You can see that there were 16 sets. These are alphabetically arranged. But a way to think of them is we heard from all of the Railbelt electric utilities with the exception of the City of Seward. We heard from ARCTEC, from RAPA, from independent power entities, from the AEA. And we also heard from some outside companies that have been thinking of making an investment in the future in transmission facilities in Alaska.

And when you look at it in these various pockets, you can kind of start to see patterns developing. Any comments at this point, however, are preliminary. At your last meeting you decided to allow a round of reply comments. And I should add that in this I docket, which has an indefinite life, even if you have additional questions or if you want additional feedback into Dr. Scott's process that he's part of, there's probably time

in May for more comments. We'll just have to see what we get at the end of the next week.

But, in any event, the comments and the summaries taken together, I think, have been enormously helpful so far. And the fact that there isn't 100 percent consensus shouldn't surprise anyone at this stage -- you can flip to the next slide -- because if there was consensus, perhaps we wouldn't even have the process going on. Everybody would have come together and figured all this out and everybody would be pulling on the same oar.

This is a slide you see here that I think was purloined from Dr. Scott's presentation a few weeks ago, which is a very high-level question. You know, what -- what should we do, if anything? What form should it take? And what process should we take to get there? Unfortunately, there's not perfect consensus on that. You can flip to the next slide.

You know, some have suggested there should be a lot of RCA involvement. Others have suggested maybe not so much. One of the patterns you'll notice is those entities that are more eager for the RCA to step in and make something happen are

the same ones that seem to find a larger base of statutory authority for you to do what they hope you'll do, whereas those that are less enthusiastic for our help are a little more questioning of the level of authority in the first place.

You'll see from the first quote up here that the answer to the ISO question that you asked -- I think it was your number one -- was, no, it's not a good idea. Of those that took positions, there's a few quotes up there that say it's probably the best and the most efficient way. It will provide benefits in terms of least cost and greatest reliability.

Some of the benefits -- it's the second-to-the-last bullet -- they're talking about potential for a centralized dispatch, using the lowest cost generation, not duplicating reserves or having excess capacity, minimizing transmission investments, making the right ones, increasing reliability, integrating renewable energy more efficiently, and making the state more attractive for potential outside investment.

I think if there's a theme from the entities that are looking to maybe invest in Alaska,

anything that will make the runway more smooth for their financial landings is, obviously, going to attract a greater interest than when there's uncertainty. Money hates uncertainty. And, obviously, things are not 100 percent sure what we're going to be looking like in five or ten years.

Next. One issue you raised in your question had to do with reliability standards. You were thinking of those that are in place in the Lower 48. Of course, right now there are reliability standards. They've been discussed on a more voluntary basis. There's not 100 percent unanimity around the Railbelt. And there's probably, it would appear, some flexibility in how strongly those standards are applied.

Thinking about this, for the Commission to mandate some type of reliability standards and enforcement you have to think there needs to be an organization set up to do that. Is the RCA going to be the policeman of that? There's got to be a lot of thought put into how to customize the national model to the Alaska situation, which, inevitably, is always different. So there's a fair amount of work.

One thing to keep in mind is all of those potential benefits that passed in the current modeling show, you know, "X" million dollars per year depending on assumptions. That isn't captured just having mandatory reliability standards. That has more to do with pooling and centralized dispatch, centralized planning, that whole array of choices that are out there. So there's not a clear dollar payoff; in fact, it may be impossible to measure. But mandatory reliability is something that might be closer to something within clear authority of the Commission to get involved in. So it's a way that you may become involved initially.

You heard a lot of -- in these comments, a lot of talk about what is the best way to proceed? Some people like an independent system operator rather than just a system operator. If you're an independent power company, you don't want to have to worry that the owner of the transmission line will make you kind of ride shotgun and prefer the owner's transactions over yours. And so they view -- and this was something that came out of the FERC years ago -- an independent system operator, somebody everybody can trust because he

doesn't have a dog in the fight. He's truly independent.

One extreme is, you know, minimal involvement. At the other extreme is we need to work toward a TRANSCO which would plan, own, and operate the whole transmission system completely separate from the generation owners. There's any number of stopping places in between.

Next. Something that in putting these together Anne Marie highlighted for you is the phrase, "no clear consensus." I think we can maybe paste that at the top of every slide. But that doesn't mean there weren't good ideas. I think the real question becomes: What can this Commission do helpfully to move a process forward and yet at the same time treat everyone fairly?

It's a wickedly complex matter to enter into. And given the spottiness of our current statutory authority, you may be able to cobble together enough authority to make something happen. But you also with your other arm may have to fend off legal challenges to it. If you had a more clear mandate, you could work with both hands, perhaps.

When you're dealing with these pieces of authority, whether it's conditioning a

certificate, reliability, conservation, management practices, reliability, all these different statutes, to use any of those or all of them together as your statutory basis there will have to be very strong factual bases, evidentiary bases for acting. And that, of course, can't be accomplished in this I docket. It can't be accomplished in an informal study. That would require an R docket or perhaps a U docket to ferret out all of the viewpoints and all of the facts, a very protracted and involved process and more than a day or two of hearing, I would guess.

There's a question of, if you do have kind of a goal in mind, do you start small or do you take an immediate leap toward that goal? That's -- that question was out there. And I don't think it's perfectly answered. We can move on.

So not only was there no clear consensus as to what to aim for, there wasn't a clear consensus on how to proceed. I think when you shake it together, there's probably a need to count the costs, look at what resources we can deploy, what authority we have, and perhaps start with a few small steps rather than trying to swallow the entire thing at once.

I think when you step back and look at the whole Railbelt, there clearly are some of the utilities that have a plan in mind and they'd like to execute on. There's others that are concerned that it's going to financially disadvantage them and their customers. If there is a way to sort all that out so it's a win/win for everybody, it's not something they've figured out yet. It's something you would have to figure out with them if you get involved.

But it's almost as if the ones that want to move forward are trying to enlist our help to make it happen and find a path through so that everyone can buy into it, a daunting task but, obviously, worthy of consideration. It's on everyone's mind. The amount of comments we've received, I think, illustrates that it's of great importance to a lot of people. Thank you.

CHAIRMAN PICKETT: Before I see if any of the Commissioners have any comments or questions at this point, I would just like to lay out what my intent is on a going forward basis. After we do receive the reply comments, we will add the entire comments to the binders. The Commissioners have all of the full filings with

us. And then we'll have Anne Marie and David add it to the matrix. And at the first public meeting that is practical in May, we'll take this up in a little more detail and see if there's more discussion or, as David suggested, quick turnaround, specific targeted questions we need to be making.

So with that, at this time are there any Commissioner comments or questions for David or Anne Marie? Thank you for your effort. I know It's been short turnarounds for you with the Commission's workload. So I appreciate the efforts you made to be here this morning.

At the end of David and Anne Marie's presentation the issue of reliability was brought up. And I think it's fair to say the Commission sees that as one of the integral components of the report we will be giving to the Legislature. One of the challenges with reliability is: What is the baseline you're dealing with? When you look at the NERC and FERC outside, the reliability standards can be fairly granular and the consequences for violating them can be quite severe with rather draconian fines.

I'm not sensing that's the direction we at

this point really want to go. But, you know, you need to know where your starting point is. And I think by and large we've had a reasonably reliable system given the environment we are working in.

And so the question is: What else? And as a starting point, we have directed our staff -- our internal staff to look at our own electric utility outage reporting for an extended period of time, see if there's gaps there perhaps in our own regulation or how the reporting is being executed. And towards that end, we have Jay Layne from the RCA engineering department to give a PowerPoint presentation on what you discovered.

So, Mr. Layne, please proceed.

MR. LAYNE: Good morning, Chairman Pickett, Commissioners. My name is Jay Layne, and I'm a utility engineering analyst in the engineering section here at the RCA.

My presentation today is a summary of the data reported by the electric utilities to the Commission concerning service outages. The purpose of today's presentation is to review electric utility industry reporting requirements as required by regulation, review the reports and data submitted by the electric utilities, and

maybe make some suggestions to the process.

3 AAC 52.460(g) describes the information required to be reported for an outage. The regulation was drafted in 1987 and has not been updated since. I've summarized the regulation here in red and it says, an outage record must include cause, planned or unplanned, duration, location, and number of affected customers.

This regulation does not set a minimum for duration or the number of affected customers. But maybe unfortunately, this regulation does not require the utility to submit the information to the Commission.

So what information is required? 3 AAC 5.490(b) describes the information required and the minimum criteria that cause a utility to report an outage. As you can see, it differs from the regulation on the previous slide. This regulation was also drafted in 1987 and has not been updated. I've summarized the regulation here in red. And the utilities are required to submit outage information when immediate threat to health or safety and the outage affects greater than 5 percent of customers or discrete community and -- this is probably a very big deal --

persists for more than three hours.

So who is required to report? The Commission has certificated 125 electric utilities across the state. 33 are economically regulated. And of the 33, 12 are not included in this report: The three Doyon utilities that serve the three bases and nine wholesale utilities. So 21 are evaluated in this report. A quick definition of wholesale versus retail. Wholesale electricity sells to another utility for resale. Retail sales are made to consumers like me and you and businesses.

Here is a list of the wholesale -- wholesale electric utilities that we do regulate but are not included in this report. Most of them just have one customer.

The scope of the available data: This PowerPoint presentation covers a period from 2003 to 2013, 11 years, roughly 260,000 meters. And the City of Seward is not included -- they're a political subdivision -- and neither is Adak or Kodiak. Another regulation requires that the electric utilities submit an annual outage report.

So who is reporting their outages on an annual basis? We have on the chart here you can see CEA from 2003 to 2013 has submitted,

basically, ten out of 11 annual outage reports. And beside that you can see they did submit their 2013 annual outage report. And we do have the lion's share of customers being represented here with CEA, MEA, ML&P, and GVEA being fairly consistent on their reporting.

We have annual reports due and we have single event outage reports, which is outlined in the regulation here on the slide. And so who is submitting their single event outage reports? You can see here the total number of reports varies widely from one all the way to 34. And for an 11-year period we have here at the Commission 103 single event outage reports. And the six utilities listed here have submitted 92 percent of those reports.

So maybe an intuitive question would be: Does the annual report data equal the summation of the single event reports for 2013? This slide shows all the single outage event reports the Commission received for 2013. As you can see, the Commission received seven annual reports out of 21 utilities and 34 single event reports.

The lack of single event reports may seem inconsistent, especially with MEA and ML&P having

submitted only one for 2013. But the criteria for them to submit a report is maybe counterintuitive.

So in conclusion, you can see that reporting of the outage information is inconsistent with a few exceptions. So my conclusion, consistent reporting from the utilities will allow the Commission to determine if a utility is becoming more reliable or less reliable in providing service. Maybe be able to rank the reliability of the utilities or compare their performance against one another. And, hopefully, one day maybe be able to determine if a utility's annual outage report and single event reports reconcile.

And I've listed some short-term priorities for us in the engineering section. Send a reminder letter to all the regulated utilities regarding the outage monitoring and reporting requirements. Send an example of a complete or maybe an ideal annual outage report. Send an example of a complete or an ideal single event outage report. And maybe make a friendly request for the detailed outage records that they're not required to submit but are required to keep on record. That would probably help us connect a lot of the dots.

And with all of -- if we get more complete reporting, we would be able to -- able to calculate some commonly -- commonly used industry standards for reliability. The system average interruption frequency index can plainly be stated: On average, customers on the distribution system experienced blank -- "X" service interruptions in a year. Another industry index is system average interruption duration index, and that can simply be stated: On average, customers on the distribution system were out of service for "X" minutes per year. And last but not least, customer average interruption duration index can simply be stated: The average customer that experienced an outage on the distribution system was out for "X" minutes.

And potentially some long-term goals would be to maybe draft regulation that would define the data required in the annual outage reports. A common standard is IEEE Std 1366. Modify the requirements that trigger mandatory single event outage reports. And that would allow us to compare apples to apples and see if there are trends in increased reliability or less reliability. And that is all.

CHAIRMAN PICKETT: Thank you, Mr. Layne.

Are there any Commissioner questions at this point? Seeing none, we'll ask Dr. Scott to move to the laptop and continue.

Is your mic on?

MR. SCOTT: Now it is.

Good morning, Mr. Chairman, Commissioners. My name is Antony Scott. I work for the Alaska Center For Energy and Power. Reminder: The Legislature -- Legislature charged you with recommending whether an ISO or similar structure was the best option for effective and efficient electric transmission. I -- the focus today is going to be on the reliability aspect of these two words "effective" and "efficient."

So the reason, of course, is because reliability will be affected by -- and is affected by the transmission system in the Railbelt. And reliability will also be affected by any change that you make to dispatch institutions. So it will be inherently an issue that must be wrestled with, a set of policy choices that have to be addressed in any change that you make, if any, or any change that you recommend, if any.

So, broadly speaking, I'm going to hit on these three broad topics. And I want to talk a little bit about reliability and market failures, what economists call market failures. I want to talk a little bit about assessing the Railbelt reliability picture today. And then, finally, just sort of point to some policy choices that you're going to have to -- have to address.

So the concept of efficiency tends to be cashed out. We tend to think about it in terms of, well, are the benefits greater than the costs? And if the benefits of doing something are greater than the costs, then, yeah, you should do it and make the system more efficient. In the case of reliability, that's a hard thing to do. It's hard to do because reliability is unpriced. In a general market economy if you want to know what the value of a T-shirt is, you can go across the street to the mall and the price reflects its value.

The reply -- the price reflects its social value. Because anybody can produce a T-shirt, relatively speaking. There's no monopoly there. There's no economic regulation. There's free entry and exit. So its price in the market tends

to reflect its value. That's not the case in the industry that you regulate. The value of electricity service is substantially greater than its cost for consumers. And, indeed, that is why you regulate, because there are natural economies of scale and scope. It's also, of course, the case that there is no particular market price that you can go out and find for the value of reliability.

And so what that means is that to assess the customer value for reliability, things get squishy. Economists tend to do surveys or you set up little experimental games or you try to elicit, but it's quite hypothetical. And, as a result, you know -- so I was putting this together last night and came across, you know, a number of engineering sort of assessments trying to help utilities manage and justify measures to improve reliability of their systems, for example.

And one benchmark for -- that was used for the value that a consumer might place on reliability was $0.40 per customer minute. So to avoid an outage I'd pay 40 -- of a minute, an individual residential customer might pay $0.40. If, hypothetically, you were to have an outage

that affected around 6,500 customers for, say, four hours and you were to take measures to reduce the like -- the occurrence of that, in a year if you were just to linearly extrapolate you get something like $600,000 worth of benefit from reducing that single outage, which is a relatively minor one.

The numbers can get very big as you multiply the number of customers. And a theme that we're going to return to again and again is that we tend to kind of wrinkle our noses at that stuff because it's like, well, yeah, but really. But I would urge you that there's lots of things that are not priced, but it doesn't mean that they're not valuable.

So there's another problem around economic assessment of reliability, and that's that in providing reliability -- because we don't have individual markets. Because we provide electricity in a network way, the reliability that -- the value that my neighbor might place on a reliable system may be greater than my own, right? And yet the cost of providing reliable service for my neighbor is going to be, essentially, identical from the utility

perspective as the cost of providing reliability for me.

So one of the things this raises is, well, does it make sense to structure the reliability of the system overall for my neighbor's persnickety, high-demanding set of values and concerns? And, you know, I don't really care very much because I don't use much electricity.

So this is actually -- unlike t-shirts, are really actually material problems. And it involves you all as policymakers in the determination of certain social values that -- it's -- you cannot extricate yourself from this. The other group effect thing that's kind of funny about reliability which is unlike many market outcomes, is that the customer valuation that we place on reliability tends to be a function of the reliability that we have.

If we have a highly reliable provision of a service, we tend to organize our lives and our economic activities around that reliability. So disruptions become costly if we're not used to disruptions. On the other hand, if we're used to the power going out for four hours a day every day, it's inconvenient. We might be hot and wish

we had air conditioning. On the other hand, you get used to it. And so cross-cultural assessments of reliability turn out to be highly affected by the baseline system that you have.

It's clear, though, that in general increasing -- reliability is increasingly important for a modern economy. In general, electricity reliability is very high in industrialized societies and economies optimize around that. So, again, the decisions that we make about the kinds of service that we offer in the Railbelt and the surety with which it is offered will have consequences potentially for the economic development opportunities in the Railbelt as a whole.

Now, all this stuff is squishy, right? Talk to me about tariffs. Talk to me about rates. Despite the fact that it's not a price that you can look up in the marketplace, it's not a tariff that you can issue and say, okay, that's what it's worth to folks, it may be the most important aspect that is affected by decisions around an effective and efficient Railbelt system.

Another set of market failures has to do with the provisioning of the service and reliability.

We've got an interconnected system. The way that electricity works -- and given two different providers who are interconnected on the system -- is the -- if I'm a utility and my neighbor's a utility, her actions affect the reliability of the service that I can provide. The amount of spinning reserve that they carry or, indeed, even the procedures that they use to bring on a new plant. Whether or not there ends up being a problem when that plant is brought online is in some ways irrelevant if we think of reliability as involving risk, not just of actual outages but the risk of an outage.

Because, after all, risks are costs. So my neighbor's behavior in the provisioning of electricity service affects the values received by my customers. And the decisions that they choose to make involve costs that their customers don't necessarily fully bear, because the costs are bigger and spill over and are -- so they're not fully captured by that utility's behavior and decisions that they make with regard to their own customer base.

This last point is a little bit subtle. I said it before, but I come back -- want to come

back to it. The externality, again, around reliability has not to do just with whether an actual outage occurs. It has to do with whether my neighbor's conduct is risky and might increase the likelihood of an outage for my customers. Because, in general, most of us are willing if we -- to ensure against risks. So there are costs associated with creating greater risks for me.

So how reliable is the Railbelt electricity system? There's sort of two prongs for thinking about reliability. One is the end result, right? We had earlier discussion of different index measures -- which, today, you don't have available to you -- that would allow you to characterize a given utility's reliability either compared to its neighbors or over time.

And from our perspective, I mean, we've seen we don't have the data to assemble those indices right now. It's quite unfortunate, I think, from -- actually, from the utilities' perspective. By all accounts, as I understand it, the system as a whole is considerably more reliable than it was, say, 20 years ago. It's too bad that there isn't a track record to be able to demonstrate that beyond historical memory.

Data is very use -- is very useful for telling an appropriate success story. And it's -- there -- there will be benefits for the parties involved, I think, actually in terms of being able to document and demonstrate how well they're doing.

So the other aspect of reliability, though, that I referred to before has to do with risks. And that really gets to processes where you look not just at whether there's an outage and how often there's an outage. But reliability needs to be thought, in part, in terms of conduct and processes to manage those risks. Why? There's a significant portion of a lack of reliability that is due to statistic events, right? That is, outages occur at random.

There -- it's a risky world out there. Things happen in unpredictable ways. The processes that we put in place to manage those risks, obviously, have an effect on the frequency and likelihood of an outage. But it's also the case that a given utility could go many years and never have an outage and it was just because they got lucky.

So merely the absence of an event doesn't

necessarily mean that the utility's particularly doing a great job managing those risks. Nor is it the case that having a bunch of events in a given period of time means that they're doing a poor job. So all of the reliability institutions focus very heavily on processes, training, and conduct as part of this.

And, indeed, if you look at the -- the fines that are levied -- ultimately, at the end of the day, by the FERC under FERC auspices under the Federal Power Act -- more often than not, those fines are associated with violations of process rather than actual outages. And so maintaining processes to manage those risks turns out to be something that is actively managed not infrequently.

So we jumped the gun in the presentation just a little bit. But how reliable is the Railbelt? We -- in historical terms I think everybody seems to be of the agreement -- and I can't say because I'm a relative newcomer. I've only been here since 2000. But in historical terms, my understanding is the Railbelt's more reliable than it used to be. I can't demonstrate that for you. And, unfortunately, I'm not sure that anybody can.

And that's unfortunate. It's hard -- it's hard to make a good case without data, and yet data are possible. They can be collected and properly assembled to help indicate a picture of this.

We also don't have good data, as we've seen, because of inconsistent reporting. Not just insufficient detail, but insufficient compliance reporting to be able to benchmark one utility's performance against another within the Railbelt. And then, finally, we've got a lack of good data on the reliability of the bulk power system separately from the reliability of the individual utility distribution system.

The charge that the Legislature gave you, I read, as primarily directed towards the bulk power system. That is the generation and transmission of electricity rather than its distribution. It is not easy based on just -- not only the data that you have, but, in general, this is a harder problem that regulators and other entities outside have been wrestling with for the last ten years. It takes some work to separate reliability reporting in the bulk power system as separate from reliability in the distribution system.

The vast majority of outages are generally

understood to be distribution outages, as opposed to bulk power system outages. Bulk power system outages are less common and, obviously, much more noticeable and widespread. When they happen, they tend to affect a lot more people.

There are also -- the bulk power system issues are also inherently at play here in terms of this issue around utility externalities, so where the conduct of one utility affects the other utility's reliability. Those -- what we're really talking about here are bulk system externality effects rather than at the distribution level where a tree in a neighborhood falls over.

So we don't have particularly good data at least publicly. And I would suggest that that is at least an issue worth looking at. It's hard to manage what you don't measure. I'm not suggesting that the utilities themselves do not measure this. I don't know what they collect. I don't know -- I mean, I don't think -- I think we do -- we don't know.

I think we have to assume, though, that there's an awful lot of data that they are collecting and they've got a pretty good handle on what's going on. But we also know that as a

general matter, increased levels of accountability even if it's just to each other is useful for ensuring reliable operation of any complex system, right?

The biggest change that has been made in, say, aviation safety over the last 20 years -- the big innovation has been pilot checklists where pilots and copilots go through checklists and they check each other to make sure that a standard list of things are gone through. Do these guys know and -- and gals know what to -- how to fly a plane? Absolutely. Is going through a checklist and holding each other accountable in the few minutes before taking off useful? Absolutely. It's the single biggest change in aviation safety.

In general, in terms of managing complex industrial systems, there's agreement that bringing that kind of oversight and accountability in a more robust and resilient way produces good outcomes. From a process perspective, how reliable is the Railbelt? We can contrast it with federal processes and procedures. I'm not suggesting for an instant that the federal system is the appropriate system for Alaska. But it's worth looking at, I think, as at least a

touchstone, in part, because there's been a lot of innovation on the federal side.

This is an incredibly deep and broad subject, and I'm not going to pretend to try to fully cover it. But if you look at NERC's program areas -- which are currently critically affected by the 2005 Energy Policy Act, which amended the Federal Power Act -- we have mandatory reliability standards. Those standards are industry driven, but they're open. The process for developing those standards are open, which means people -- interested parties can contribute and do.

The standards are mandatory. They're not -- they're substantially process standards. The NERC is involved in realtime risk management of the bulk power system. They are working to collect and monitor data from the bulk power system more or less on a realtime basis so that they can then ensure that there is learning from events that happen, and, also, so that the system is being monitored and appropriate actions are being taken.

Now, again, these are innovations. And increasingly what we're seeing outside is from the blackouts from the 1960s increasing levels of oversight, complexity, and redundancy in these

processes. NERC is involved in training, education and system operator certification. This sounds kind of like soft stuff, right? It's like, oh, you know, training. Nice. But the formal training and certification is critical because only certified entities are allowed to perform certain functions in that bulk power system.

Compliance and enforcement. If you violate the standards, there are fines. Sometimes the fines are very material. So at the federal level there's a very complicated set of levels of the devolution of authority from the FERC to the NERC and then to the regional reliability organizations which then further push out monitoring and behavioral responsibilities to various entities.

But, indeed, there is compliance and enforcement for all of the players in the system as a whole. And then there's ongoing reliability assessment and analysis looking at the data, identifying trends, trying to see forward looking what are emerging issues that will affect resource adequacy; and what are emerging issues that might have bearing on future standards. All told, then, what we have is not just reliability means you've got a set of standards and then you're done with

it; but it's a very involved, ongoing, living process of accountability across the actors and across levels.

The state picture is much more informal and less transparent. You all have statutory oversight on service quality on a utility-by-utility basis. I think everybody agrees with that. The IMC's promulgated what I think needs to be understood as non-mandatory reliability standards. Not everybody in the Railbelt is -- has signed onto those standards.

Dropping down to compliance and enforcement. But it's also the case -- I think this has been pointed out in comments that you've received as part of this docket that -- as well as correspondence that you've received recently -- that the parties in the Railbelt don't always fully adhere to their own standards that they've signed onto. So IMC standards which certain members are party to are not -- in terms of process standards, they're not always fully adhered to. Is that a problem? Maybe not. Maybe not.

But there -- it's funny to talk about mandatory standards when there is no enforcement

for deviations from those standards. We don't have a process in which anybody can clearly be -- can receive sanction. From a risk management perspective, I'm at least -- I am unaware of realtime assessments of the bulk power system. I could be completely wrong on that question. But I'm not sure that anybody has taken that on. Clearly, the bulk power system operates pretty reliably.

I mean, at some level, all of the operators across the load balancing authorities are aware of what's going on and are managing their individual balancing areas accordingly, and they're coordinating their actions informally across the system. So it's not the case that it's the wild west out there. What I'm talking about instead are monitoring systems that are geared specifically towards understanding what's going on with the bulk system as a whole and then documenting that, creating data from that, and then using those data to -- to create what people in the oil industry call learnings.

So we've seen from a risk management perspective public reporting of outage data is uneven. Again, this is not necessarily a problem.

In general, one would expect that the more layers of mutual and reciprocal accountability that we have in the system as a whole, the more reliable it will be. So the more transparent these processes are and so on, in general, you would think, the better. Just like pilots and co-pilots hold each other accountable by going through those checklists, in general, you would think that more public accountability would be useful for reliability.

At the same time -- and I think I alluded to this last time -- there's understandable reticence, I would imagine, for involving parties that lack particular expertise in the technical details and giving them a peek under the hood about what's going on. It's an understandable and reasoned set of concerns. Because, after all, if you -- you know -- I mean, you don't want someone who's not a surgeon looking over your shoulder while you've got somebody opened up on the operating table and go, oh, that looks really bad. You should do something about that over there. I mean, they're just not trained.

And merely having to take the time and explain things and address that is costly and

diverts from the mission at hand. And so whether it -- the benefits associated with oversight are worth the costs is a very reasonable set of concerns to have.

We don't have formal institutional requirements around reliability training and certification. This is not to say that the utilities don't have internal programs for training. I'm sure that they do. There -- because you don't have mandatory standards around certification, however, it's also pretty clear that the coverage and adherence to whatever the trainings are is going to be subject to potentially more slippage than if you did. That's all. And, clearly, we don't have compliance and enforcement around violations.

So -- so what should you do? Right. Well, clearly, it's too early to address this. You do have statutory oversight around quality. Essentially, you have left management of these issues substantially for the utilities to handle. And what I heard the Chairman say a moment ago is, in general, that's worked pretty well. And it is worth pointing out, though, that, in general, there's been a lot of evolution outside.

Reliability is never a problem until it is. And then once it is, then all of a sudden we've got a whole bunch of work that people do; and they try to put systems in place and so on.

But it's a little like buying insurance after your house burns down. If it was worth putting those systems in place afterwards, it should have been worth putting them in place before. So I would suggest that you not use the recent past as an -- as a reason by itself for doing nothing.

So the last -- the last point here, of course, is institutions to manage reliability aren't free. They're expensive. You have certain costs and very uncertain benefits. So as a commission, politically you're in a terrible position even if you thought it was extremely important to do this to have -- to have increased levels of oversight, of data generation, of public accountability, because that involves imposing costs with very uncertain payoffs. And the kicker is you will never know -- no one will ever know whether it was worth it, because you don't know what would have happened in the absence of those efforts. And you can't know.

I would suggest, though, that, in general,

it's widely acknowledged that we have a lot of human capital in the Railbelt in terms of managing these systems. The human capital is not getting any younger. There is, I think, widely understood that you've got a lot of wisdom and know-how in understanding about how to run systems and the people that currently run them. And those people are getting ready to do other things.

One of the values of having institutions is you create structures to make the knowledge that's in those people's heads easily passed down in a systematic and careful way. And so there is potentially an opportunity in terms of thinking about this question if you want to move beyond the current approach, which, again, is hard to argue with results. Things are better, as I understand it, than they used to be. Substantially.

But potentially one of the values of having institutions is you can ensure that the results and the know-how that were painfully created and learned and are in the heads and bodies of a bunch of people who currently manage the system are passed through to new folks in an institutional way.

So just to underline -- this is probably the

major point. Just because reliability is unpriced and unpriceable, it doesn't mean that it's worthless. Some of the biggest benefits, potentially, from having -- from doing things differently in a bulk power system in the Railbelt may come from having a more reliable system. And the benefits are not -- are in terms of welfare of individual consumers, in terms of the economic development opportunities that are afforded of this sort of most basic and critical infrastructure.

It's not easy to measure where we are today, And that's unfortunate. Because I think the existing systems and practitioners in this -- in the current system would have a better -- it would be good if they could tell their success story in a more objective data-driven way. It's unclear to me whether the institutions affecting the practice of reliability in the Railbelt are sufficiently resilient.

I mean, this is a question in every -- in any institution I've ever been in, the issue of institutional memory and knowledge is always a concern. And I have yet to be in an institution that managed it particularly well. It's a lot of

work to pass down institutional knowledge. It's not easily done. This is not to say that the utilities are not doing a very good job of it. I don't know. It's just -- it's a question. The thing is, if they don't, it affects everybody. And you can be sure that all of the people involved in the day-to-day operations in management are doing their very best as they see it, just like pilots do when they take off.

I would suggest that any recommendation that you make to the Legislature probably should address the question of how reliability will be assured, one way or the other. It is almost certainly a necessary consequence of any change that you would recommend, and it will raise issues about how it should be dealt with.

So, again, I have absolutely no recommendation at all to make on the subject, but it's both hard and potentially one of the most important questions at issue on the docket, and you can't do it subject it to cost/benefit analysis in any easy way. So thanks very much for your time.

CHAIRMAN PICKETT: Before -- before I open it up for Commissioner questions, since you

threw a porcupine our way, I'm going to throw one back at you. And that is, through your presentation you have alluded to non-billed values. In fact, at page 3 you sort of had that as one of the bullets there. And one of my criticisms of the EPS study -- the pre-Watana EPS study was as you looked at it and looked at particular projects, it appeared that some of those values were sort of built into the assumptions, as opposed to hard costs, construction costs type data.

So give me a succinct definition of non-billed values that even a cost-of-service regulator and RAPA can understand.

MR. SCOTT: So in the EPS study -- I think you're asking for non-billed value of reliability. Because there are lots of other ones and we alluded to that last time in the non-billed value of independent -- not needing to depend on anybody else is an Alaska value. It's non-billed.

But in terms of reliability, on this slide, right, this is a sample calculation of the sort that showed up in one particular set of benefits for one particular set of transmission improvements in the EPS/AEA study, the pre-Watana

study.

So a customer benefit from reduced outages is ascribed $0.40 per customer minute. Like, that particular example off the top of my head, I can't remember what the basis is. But it's this kind of calculation, $0.40 per customer minute. Well, you reduce the likelihood of an outage affecting "X" thousands of customers in a year by engaging in these improvements, right? So take $0.40 per customer minute and multiply by the number of minutes per outage and multiply by the number of customers and you get a number, right?

It's that kind of calculation that was embedded in the EPS study to try to get a sense of -- I love this music -- to try to get a sense of what the overall benefits on a non-billed basis might accrue to that transmission improvement.

CHAIRMAN PICKETT: Okay. But there are cases -- and you're talking about on the utility side of the meter as they're doing -- because there's customer sides of the meter where certain types of customers -- i.e., hospitals, the bases -- have an entirely different type of calculus. And it's whatever it takes to keep critical mission functions going. And they will

spend whatever self-generation they have to do to back that up.

MR. SCOTT: Right. That's right. And one of the things that we're -- that you're sort of alluding to there is -- and this is just a hard problem -- is that some parties have very high demands for reliability. And so then the question is: Do you manage those needs and expectations on the utility side of the meter or on the customer side of the meter?

And where those break points are is a question -- really, fundamentally a question of public policy, in part, because of this second bullet here that the customer valuation of reliable service is affected by the baseline level of reliability provided.

CHAIRMAN PICKETT: Thank you. Are there any other Commissioner questions at this point for Dr. Scott?

Well, thank you very much. And just for looking forward, next Wednesday is a special public meeting that will probably run from 9:00 to noon. The only item on that agenda will be this I-15-001. And it is our intent to roll out some of the -- a description of some of the modeling in

cases and things that the Commission has been looking at for the better part of a month and analyzing it and thinking about it. And so we'll -- this will be sort of the rollout for that part and would encourage you to come at that point. With that, I will close out agenda item number three.

Number four, do any of the Commissioners have any other business that needs to come before us this morning?

Number five, does the attorney general have need for an executive session?

MS. POKON: No.

CHAIRMAN PICKETT: Is there a motion to adjourn at 10:50 a.m.?

COMMISSIONER PATCH: So moved.

CHAIRMAN PICKETT: Second?

COMMISSIONER McALPINE: Second.

CHAIRMAN PICKETT: All those in favor say aye.

(Collective aye.)

CHAIRMAN PICKETT: Opposed?

Passes unanimously. Thank you for being here this morning.

(Adjourned - 10:50 a.m.)

I-15-001 In the Matter of the Evaluation of the Operation and Regulation of the Alaska Railbelt Electric Transmission System

How do the responses to Order I-15-001(1), *Order Opening Docket and Requesting Responses*, dated February 27, 2015, help us arrive at a Policy Options set forth at the April 8, 2015, Public Meeting

Presented April 22, 2015

Order I-15-001(1), *Order Opening Docket and Requesting Responses*, dated February 27, 2015

- We opened this docket at our February 27, 2015 Public Meeting, and issued and order that requested specific input regarding a directive from the Alaska State Legislature. We received responses from:

- AEA ~ *Alaska Energy Authority's Response to Order No. 1*, filed March 31, 2015;
- AEP ~Correspondence from Craft, M. dated April 1, 2015;
- AIPPA ~ *Alaska Independent Power Producers Association comments*, filed March 31, 2015;
- APA ~*Initial Comments of the Alaska Power Association*, filed March 31, 2015;
- ARCTEC ~ *Comments of Alaska Railbelt Cooperative Transmission and Electric Company, Inc. in Response to Questions Posed in Docket I-15-001(1)*, filed March 31, 2015;
- ATC ~ Correspondence from Meyers, Eric. Dated March 31, 2015;
- CEA ~ *Chugach Electric Association Inc.'s Response to Questions Posed in Order I-15-001(1)*, filed March 31, 2015;
- CIRI ~ *Cook Inlet Region Inc.'s Comments Responding to Commission Order No. 1*, filed March 31, 2015;
- GVEA ~ *Golden Valley Electric Association Inc's Response to Commission Order Seeking Comments*, filed March 31, 2015;
- HEA/AEEC ~ *Response by Homer Electric Association to Questions Posed in Order I-15-001*, Filed March 31, 2015;
- MEA ~ *MEA Responses to RCA*, filed March 31, 2015;
- ML&P ~ *Municipal Light and Power's Response to Order No. 1*, filed April 3, 2015;
- Power Bridge ~ *Comments of ARES EIF Management, LLC and Power Bridge, LLC*, Filed March 31, 2015;
- RAPA ~*Office of the Attorney General's Response to Order I-15-001(1)*, filed March 31, 2015;
- REAP ~ Correspondence from Rose, C. dated April 1, 2015; and
- Xcel ~ *Response of Xcel Energy to Order No. 1*, filed Marc 31, 2015.

At our April 8, 2015 Public Meeting we posed the following questions:

- Policy Options
- Status quo, or something new?
- If something new, what?
  - Mandatory Reliability Organization?
  - Transco?
  - Mandatory unified dispatch (ISO/RTO vs tight pool)?

- If something new, then gradually or all at once?
- If something new, then how (process)?

Status quo, or something new?

- One commenter advocated the status *quo*:
- "The creation of an independent system operator or similar structure for electric utilities in the Railbelt would not be the best option for effective and efficient electrical transmission…The current system is relatively simple and inexpensive to operate."
- Four commenters thought they needed more information
- The majority of the commenters expressed varying degrees of support for change:
- "implementation of an ISO, USO or RTO is the best option for delivering low-cost, reliable and sustainable energy to consumers, at today and into the future."
- "believes the best option for effective and efficient electrical transmission in the Railbelt is creation of an entity empowered to implement long term electric transmission infrastructure planning and oversee final development, and periodic refreshment, of open access provisions and reliability standards the system will operate under."
- Benefits could include: centralized economic dispatch; lowest possible cost generation; elimination of duplicate reserves and over capacity generation; elimination of duplicative transmission assets.; increased reliability; increased integration of renewable energy; and increased likelihood of independent investment.
- "Creation of a stakeholder driven Unified System Operator (USO) … will provide the least-cost and most reliable Railbelt power system in the future."

If something new, what?

Mandatory Reliability Organization? Transco? Mandatory unified dispatch (ISO/RTO vs tight pool)?

- Mandatory Reliability Organization ~ None of the commenters mentioned a "Mandatory Reliability Organization," but the majority of the comments indicated that to some extent there was support for reliability standards and most mentioned that Railbelt utilities generally adhere to a set of standards set by themselves. There was no consensus as to a particular entity with reliability oversight. Some commenters felt that an SO would provide reliability oversight, some thought that stakeholders would provide oversight, some thought that the Regulatory Commission might provide oversight.

- There was no agreement as what a new Railbelt environment might be. Some commenters provided no specific comment, some provided detailed comment as to the path that should be taken and included fairly specific steps on how to implement to the changes envisioned; including an ISO, a TRANSCO and pooling. Some commenters only submitted cautionary warnings about the pitfalls of a particular operational pathway.

If something new, then gradually or all at once?

- No clear consensus.
- Comments suggested no change without further study and consideration.
- Comments urged slow changes in small steps.
- Comments urged immediate and comprehensive changes.

If something new, then how (process)?

- No clear consensus on how to proceed emerged from the comments.
- Comments included detailed plans on how the utilities could proceed in developing in either an ISO or a Transco.
- Other comments urged that any steps taken be made only after deliberative process and findings being made.

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Electric Utility Outage Reporting 2003 to 2013

Regulatory Commission of Alaska April 22, 2015

Jay Layne
Utility Engineering Analyst

Purpose of today's presentation

- Review the electric utility industry reporting requirements as required by regulatory code.
- Review the reports and data submitted by the electric utilities to the Commission.
- Suggestions to improve the process.

Record all outages but…..

Utility Record Keeping:

3 AAC 52.460(g) "A utility shall maintain detailed records of planned and unplanned outages and of interruptions of service. These records must include the cause, whether planned or unplanned, duration, location of the outage, and the approximate number of customers affected. These records must be available to the public. For purposes of this subsection, a momentary fluctuation does not constitute an interruption of service."

Records must include:

1. Cause
2. Planned or unplanned
3. Duration
4. Location
5. Number of affected customers

This regulation <u>does not</u> require the utility to submit the information to the commission.

Report the outage information only when…..

Utility Outage Reports:

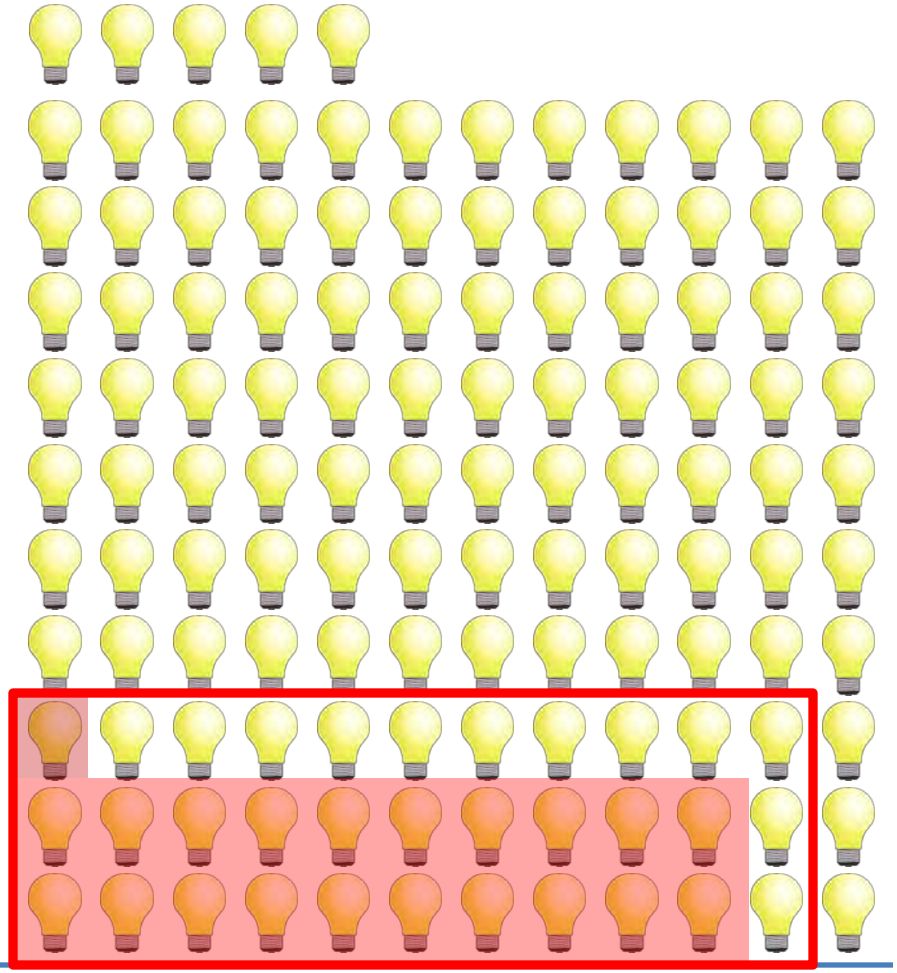
3 AAC 52.490(b) A utility shall submit information to the commission regarding service outages as follows:
(1) for an outage that is an immediate threat to the health or safety of customers within the utility's service territory, the commission must be notified immediately by the most expedient means available;
(2) for an interruption of service, from whatever cause, which affects five percent or more of a utility's total customers or affects a discrete community of customers, and persists for three hours or more, the written report must include a description of the cause and extent of the outage, and must be filed within five working days after service is restored; and
(3) a cumulative 12-month report of its service outages must be filed as a part of the utility's annual report to the commission under AS 42.05.451.

Utilities are required to submit outage information when:

- Immediate threat to health or safety; the outage affects >5% of customers; or affects a discrete community, AND
- Persists for 3 hours or more.

Who is required to report?

- 125 electric utilities certificated by the Commission
- 33 utilities are economically regulated
- 12 regulated utilities are not included:
  - 3 Doyon utilities
  - Wholesale utilities
- 21 economically regulated utilities are evaluated in this report



Wholesale vs. Retail

- **Wholesale Sales**: electricity sales to another utility for resale.

- **Retail Sales**: sales of electricity to the end-use consumer. Sales made directly to the customers that consume the energy product.

Wholesale Electric Utilities

Regulated utilities omitted from the report:

1. AK Electric Generation and Transmission (CPCN 345)
2. Aurora Energy, LLC (CPCN 520)
3. Goat Lake Hydro, LLC (CPCN 521)
4. Alaska Electric and Energy Coop (CPCN 640)
5. Kwaan Electric Transmission Intertie (CPCN 710)
6. Aleutian Wind Energy, LLC (CPCN 735)
7. Alaska Environmental Power, LLC (CPCN 742)
8. BBL Hydro, Inc (CPCN 573)
9. Tanadgusix Corp (CPCN 749)

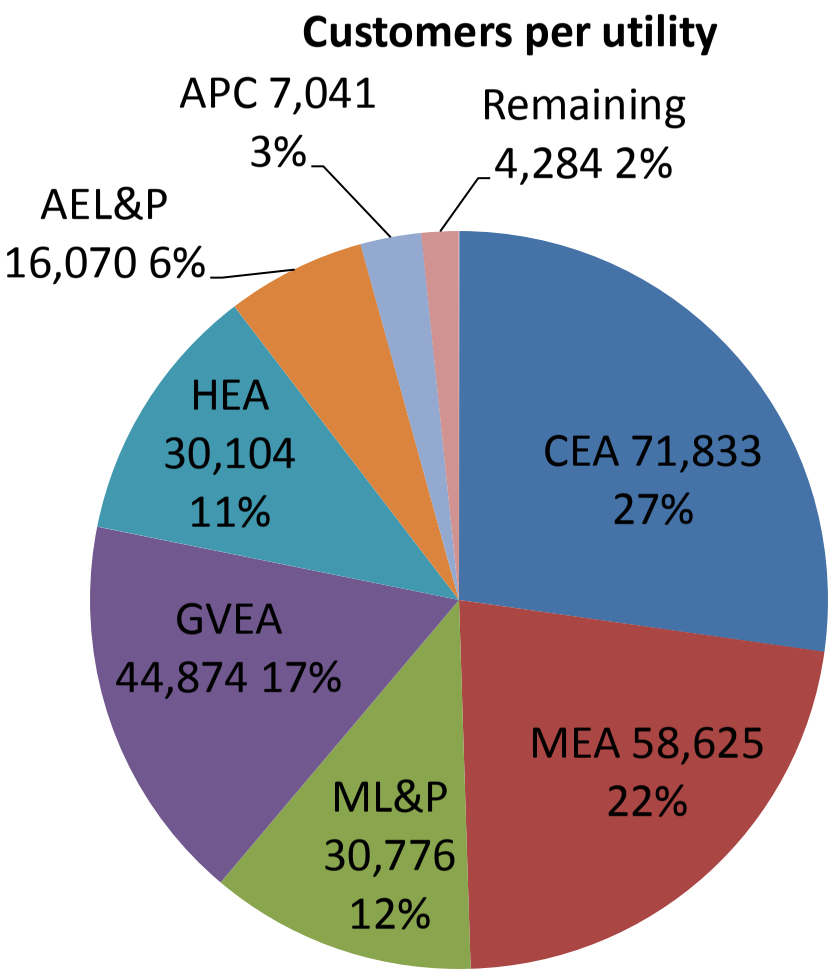
Scope of Available Data

- This report covers the period from 2003 to 2013 (11 year period)
- 263,600 meters (237,600 residential / 24,000 commercial/industrial)
- City of Seward is not part of the report (political subdivision)

Annual Outage Reports – Who is reporting?

Per 3 AAC 52.490(b)(3) – a cumulative 12 month outage report is due with the utility's annual report:

	Utility	2003 to 2013 Compliant	2013 Annual Outage Report
1.	CEA	91 %	Yes
2.	ML&P	82 %	Yes
3.	GVEA	82%	Yes
4.	MEA	64 %	Yes
5.	TDX Manley	45 %	No
6.	Aniak L&P	36 %	Yes
7.	Sand Point	27 %	Yes
8.	Gold Country	27 %	No
9.	TDX Adak	27%	No
10.	Alaska Power Co	9 %	Yes
11.	TDX NSG	9 %	No
12.	HEA	9 %	No
13.	AEL&P	9%	No
14.	G&K Inc	none	No
15.	Gustavus Electric,	none	No
16.	Gwitchyas Zhee, Inc.	none	No
17.	Inside Passage	none	No
18.	Kipnuk Light Plant	none	No
19.	McGrath L&P	none	No
20.	MKEC	none	No
21.	Tanana Power	none	No



Single Event Outage Reports – Who is reporting?

Per 3 AAC 52.490(b)(2) – must report outages that: affect 5% or more of a utility's total customers <u>or</u> affects a discrete community of customers, <u>and</u> persists for 3 hours or more.

Year	Total Reports	CEA	ML&P	APC	HEA	MEA	GVEA
2014	14	5	1	5	2	1	2
2013	34	20	1	10	1	1	1
2012	8	0	3	2	1	1	1
2011	3	0	0	0	3	0	0
2010	6	1	0	0	2	2	0
2009	8	6	0	0	2	0	0
2008	3	3	0	0	0	0	0
2007	19	14	0	0	0	4	1
2006	1	1	0	0	0	0	0
2005	2	0	0	0	0	0	0
2004	3	1	0	0	0	0	0
2003	2	0	1	1	0	0	0
	103	46	6	18	11	9	5

The 6 utilities listed represent 92% of the single event outage reports submitted to the Commission.

Does the Annual Report Data = $\sum$ Single Event Reports for 2013?

Utility	Annual Report	Single Event Reports
1. CEA	Yes	20
2. Aniak L&P	Yes	-0-
3. APC	Yes	10
4. MEA	Yes	1
5. ML&P	Yes	1
6. Sand Point	Yes	-0-
7. GVEA	Yes	1
8. HEA	No	1

Threshold for reporting is: Health or safety, or >5% or community
AND
longer than 3 hours.

Conclusion

- Consistent reporting from the utilities will allow the Commission to:
  - Determine if a utility is becoming more reliable or less reliable in providing service.
  - Rank the reliability of the utilities or compare their performance against one another.
  - Determine if a utility's annual outage reports and single event outage reports reconcile.

Short Term Priorities

- Send a reminder letter to all regulated utilities regarding outage monitoring and reporting requirements.
- Send an example of a complete annual outage report.
- Send an example of a compete single event outage report.
- Contact the utilities and request the 2014 detailed outage records as required in 3 AAC 52.460(g)

Short Term Priorities

Receive an annual outage report from all regulated utilities. This will allow the Commission to start tracking 3 major reliability indices:

System Average Interruption Frequency Index (SAIFI)

This index is the average number of times that a system customer experiences an outage during the year.

$$\text{SAIFI} = \frac{\text{Sum Total Number of customers interrupted}}{\text{Total number of customers served}}$$

SAIFI can be stated:

"On average, customers on the distribution system experienced ___ service interruptions."

Short Term Priorities

System Average Interruption Duration Index (SAIDI)

This index measures the total duration of interruption time the average customer will experience during a given year. An upward trend indicates a reduction of reliability, whereas a downward trend indicative of an increase in reliability.

$$\text{SAIDI} = \frac{\sum(\text{Duration of outage x number of customers interrupted})}{\text{Total number of customers served}}$$

SAIDI can be stated:

"On average, customers on the distribution system were out of service for ___ minutes.

Customer Average Interruption Duration Index (CAIDI)

This index indicates the average amount of time customers who experience an interruption were out of service. CAIDI is generally considered to be a reflection of repair or response time.

$$\text{CAIDI} = \frac{\sum(\text{Duration of outage x number of customers interrupted})}{\sum \text{number of customers interrupted}}$$

CAIDI can be stated:

"The average customer that experiences an outage on the distribution system is out for ___ minutes.

Long Term Goals

- Draft regulations that would define the data required in the annual outage reports. A common standard is the IEEE Std 1366 – Guide for Electric Distribution Reliability Indices.
- Modify the requirements that trigger a mandatory single event outage report.
- Have enough data to compare utilities and observe trends in reliability.

Any Questions?

I-15-001
Alaska Railbelt Electricity System

Reliability – One Aspect of an Efficient and Effective Railbelt System

4/22/2015

ACEP
Alaska Center for Energy and Power

Legislative Charge

RCA should recommend:

Whether creating an independent system operator or similar structure for electric utilities in the Railbelt area is the best option for effective and efficient electrical transmission.

What Marks An Economically Efficient Railbelt System?

- Use existing assets at least operational cost
- Least cost new generation & transmission assets for future system needs
- Business model to finance and build what is planned at least cost
- Non-billed values
- Service reliability
  - Affected by transmission
  - Affected by any change to dispatch institutions

Topics

- Reliability and "market failures"
  - Problem of valuation
  - Problem of externalities
- Assessing Railbelt reliability
  - Results
  - Processes
- Policy choices?

Value of Reliability: Individual Customer

- Hard problem!
- Better at assessing changes in probability of outage than in benchmarking consumer dissatisfaction
- **Value** of a kWh > **Cost** of a kWh
- Benchmarks of costs of consumer dissatisfaction:
  - E.g. $.40 per customer-minute
  - Example: value of reducing frequency of 4-hour outage affecting 6,500 customers from 2 to 1 events per year =

$.40/(customer-minute) * 60 (minutes/hour) * 4 hours * * 6,500 customers = $624,000

Value of Reliability: Customer group effects

- Reliability provided on the utility side of the meter can be 'inefficient'
  - Some parties may demand a higher-reliability system than others: should everyone pay?
- Customer valuation affected by level of reliability
- Increasingly important for a modern economy
  - Issue of economic development

Value of Reliability: Producer/Utility Effects

- In an interconnected system lack of standards can create *externalities*
- An "externality" is a cost of my action that you bear without compensation
- Externality may not be just an actual outage, but the changed probability of my outage caused by your conduct
  - If outages are infrequent, evenly distributed across service territories, and not severe this may not much matter

How Reliable is the Railbelt?

- Reliability is critically affected by random events
- Two prongs to thinking about reliability:
  - End-results: Compared to what?
    - Historical performance?
    - Peer performance?
    - Customer requirements?
  - Processes: Compared to what?
    - Other jurisdictions?

Data: How Reliable Is the Railbelt?

- Turns out it's hard to compare Railbelt performance to Outside utilities
  - Outside benchmarks exist, but:
- Lack of good public Railbelt data
  - Reporting consistency across events
  - Reporting consistency across utilities
  - Reporting consistency within utilities
- Lack of bulk power system-specific data
  - No good way to individuate bulk system events from distribution system events

Process: How Reliable Is the Railbelt?

- Contrast with Federal processes and procedures

Federal NERC Program Areas

- Standards
  - Mandatory, following passage of the 2005 EPAct
  - Industry Driven but Open Process
- Risk Management
  - Real-time assessments of bulk power system
  - Analysis of reliability 'events' (to enable learning)
- Training, education and system operator certification
  - Transcos, ISOs,
- Compliance and enforcement
  - Certified Regional Entities monitor and enforce standards with bulk system owners, operators and users
- Reliability Assessment and Analysis
  - Id trends and long-term emerging issues affecting resource adequacy to meet reliability standards

State of Alaska Reliability Activities

- Standards
  - RCA has statutory oversight of service quality
  - IMC has promulgated non-mandatory reliability standards
- Risk management:
  - No real-time assessments of bulk power system
  - Public reporting of outage data uneven
  - No public reporting of IMC process violations
  - No public sharing of lessons learned from events
- Training, education and system operator certification
  - No formal institutionalization of reliability training and certification
- Compliance and enforcement
  - No external monitoring for compliance
  - No enforcement for violations
- Reliability Assessment and Analysis
  - RCA has regulations for event reporting, but:
  - Little public data for assessing trends, especially for bulk energy system

"We don't care how they do it Outside!"

- Policy choices:
  - Should RCA's statutory oversight of service quality be left to utilities to manage?
  - Should RCA and the legislature wait until there's a recognized problem?
- Reliability is never a problem, until it is
  - Increasing levels of reliability oversight Outside over the decades
- Institutions to manage reliability are not free
  - Certain costs
  - Uncertain payoff – what would have happened?
  - Value in creating institutions to diversify expertise and responsibility?

Conclusions

- That it is unpriced does not mean it is worthless
- Not easy to objectively measure reliability of the Railbelt today
- The institutions affecting the practice of reliability are of uncertain resilience
- Any recommendation to the legislature should probably address how reliability is to be assured

ACEP
Alaska Center for Energy and Power

Questions?

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STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners: Robert M. Pickett, Chairman
Stephen McAlpine
T. W. Patch
Norman Rokeberg
Janis W. Wilson

REGULATORY COMMISSION OF ALASKA
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501

SPECIAL PUBLIC MEETING

April 29, 2015
9:00 a.m.

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reflect that Commissioners Wilson and Rokeberg have joined us. Is there anyone else in the Anchorage audience who would care to address the Commission this morning? Is there anyone online who would like to address the Commission? Hearing none, we will close out agenda item number one.

Agenda item number two is I-15-001, In in the Matter of the Evaluation of the Operation and Regulation of the Alaska Railbelt Electric Transmission System. Dr. Anthony Scott will be giving a presentation this morning concerning some high-level modeling and some costs and benefits of change. So with that I will turn it over to you, Antony.

DR. SCOTT: Thank you very much, Mr. Chairman, Commissioners. For the record, my name is Antony Scott; I'm an economist with the Alaska Center for Energy and Power at UAF. You're going to see this slide a lot. Your legislative charge is to recommend whether creating an independent system operator or similar structure is the best option for effective and efficient electric transmission in the Railbelt.

I'm going to focus on efficient today; and in particular, we're going to focus on

economic efficiency with some caveats. So a working definition of economic efficiency is a circumstance in which there are no more changes that you can make such that the costs of the change are less than the benefits. When you get there, if you're an economist, you're in a bliss state.

What efficiency is not is a question of who pays how much, which is to say, a question of cost allocation of -- say, joint and common costs, which is where you guys spend, as you well know, most of your time.

We have lots of disputes about who should pay how much for an existing asset, whether it's customer classes within a utility or between utilities are going over an asset which provides common benefits.

So one of the reasons why that matters, obviously, is because you focus -- how big your vision is around costs and benefits matters in thinking about the notion of efficiency. So anyway, given this working definition, there's natural focus on what are costs of changes and what are the benefits of the changes.

And today we're going to really focus on costs; we're not going to talk about benefits at all. Policy options for something new. We've talked about this before. If you're going to do something new -- if you're going to make a change or propose that a change be made or -- to the Legislature, there's several different ways that you might lead into that.

One might be to form a transco; another, which we talked about a little bit last time, would be to think about a mandatory reliability organization or some sort of unified dispatch. It's impossible, of course, to precisely assess questions of efficiency or even, indeed, costs without knowing what the changes that you're talking about.

It's -- and because this is a process which is going to involve many stakeholders, assuming that anything happens where the details get worked out over time as a function of negotiated and adjudicated decisions, no proposal for a given change can be fully articulated at that time. And that's really not your charge.

I would advise, your job is not to

to try to say exactly, here's what we will do. The -- the moral of the story then is that when we talk about costs, these are going to be stylized costs; rough sense of costs, not all of the relevant costs.

But I hope to talk about costs in each -- associated with each of these potential paths for starting or potentially finishing change. And the focus on costs we'll get to in a minute, but it's -- there's natural resistance, obviously, to doing anything new. And so there often tends to be a focus on risks and costs of whatever that new thing is.

Before doing any kind of deeper dive, I wanted to spend a little time talking about how. The concept of efficiency needs to be -- one needs to pull back. Within any given set of institutions -- and by "institutions," I'm talking about the working rules that determine who has which rights and who has which obligations -- so within any institution -- and what we're talking about here is institutional change -- within any institution, parties, assuming they've got reasonable rights and obligations -- certain degree of freewill and assuming not too much

market failure, the parties in -- in that institution will seek to do the best they can.

What that means where we are now is a function of the rights and responsibilities of each of the parties given the working rules that have been laid out by this Commission and the Legislature and given the existing set of contracts that these parties have bound themselves to; and where we are now is, in some ways, the best of all possible worlds given those rights and obligations.

So your question, in part, is difficult because you need to try to peek over the fence and see whether the set of institutions that we have now produce the goods and services that people want -- let's just imagine they're kilowatt hours -- at least cost.

I've little doubt that the decisions that people have made historically given where we are now, are reasonable decisions; they're a function of the working rules available at the time and the set of institutions -- including contracts that were available to people at the time given the limited information and foresight that everybody -- all of us have to

operate under.

The -- this is a picture that I pulled off the Web this morning; and it's a toy model about how there can be local costs minimization exercise, and that's the green dot on the left. And even though everybody's minimizing costs given their inputs, it might be the case that there's another way to produce this same set of goods and outputs at even lower costs. But to get there, you have to change the working rules; you have to change the set of institutions.

Unfortunately, it's more complicated than that. Because it's a multidimensional problem with not only lots of local optima, but different parties view the problem differently. We've talked before about -- for example, non-billed values. For some parties, the notion of self-sufficiency might be more important to the problem that they're trying to solve than minimizing the nameplate costs per kilowatt hour that shows up on people's bills.

So what is that? You know, similar set of issues around environmental entities, right, green power. Similar set of issues around energy conservation. Sometimes these things are

viewed as goals in their own right.

The reason why I'm pausing and spending a little bit of time revisiting this problem is that we tend -- when we think about problems, to understand them in little analogies, little parables. We analogize from our experience to understand the problems available.

And I'll tell you, as someone who has not spent their professional working life over the last two decades working on this set of issues, this is a complicated system. It's very multidimensional; it's very hard, there are lots of actors at multiple levels.

And as an economist, when the parable or the analogies or the little stories that we tend to bring to the table is, oh, well, let's look and try to find costs -- a state in which we can make no more change such that the cost of the change is less than the benefit that we receive, this problem isn't going to be that simple. It's not that simple for you. And although it will be described in these terms, it just isn't that simple.

One of the reasons for that is -- and we talked about this last time -- is that one

of the things produced, right, is reliable service. It's not just that it's service, but it's that the service is reliable and that reliability is unpriced; its value is endogenous to the system that you have, which is to say, how people value reliability's a function of the reliability that they have; it's dynamic.

The reliability and the overall robustness and resilience to the system that you have opens up new possibilities for economic development or not -- that may not be captured fully by the minimization of a kilowatt hour cost. So this is a lot of context, and it's a lot of kind of caveat making.

But I think it's important to understand the subsequent modeling results that you're about to receive in context, because there is a tendency to focus on the stuff that is easily captured in a number because that fits well within this little parable here. Let's look at costs against benefits on a single dimension. And then we think because we understand -- we think we understand what a unit dimensional and equality means, right, what that simple optimization is, that that tells us the answer; and it doesn't.

So what you're going to get is a set of high-level modeled costs to give us an indication of relative costs of the current system that we have or potential changes to that system. And there will be a tendency then to focus on thinking that that's the stuff that most matters.

How does this balance out against benefits? And just because it's easily quantified doesn't mean it's the most important thing.

Okay. So change, change is costly. If you're going to change from where you are now, you're going to encounter some costs; especially given that where we are now, I would urge, is something of a local optimum. It may be a global optimum, given the complex nature of the problem that's being solved. That's not for me to decide.

But to move from that local optimum means you're going to have to encounter some transition costs or we all will have to shoulder transition costs associated with setting up new institutions, potentially new investments and infrastructure. We have to sort of lever ourselves out of the green dot towards the red dot, for example.

So there are initial upfront costs.

I'm not going to talk really about any of those transition costs right now, those are essentially hard to sort of get your arms around. I lack the expertise to give you a good story around that; other people, I think, probably can. But change is costly. It involves different distributions of who bears that costs.

There's risk around how big those costs will be, and the costs come in different sorts. Again, going back to this multidimensional problem. If the costs aren't just measured in dollars, but, perhaps, in a loss of autonomy, then that might be a problem. More for one party than another. So that's a question of the type of costs.

So change is risky. They are bigger than anticipated, those costs. And really change is most easily delayed.

The first time we visited in this room we talked about how one of the work streams that we had -- or have is to do a review of the existing studies that have been undertaken in the Railbelt trying to look at ways of more efficiently or effectively organizing, and they've been -- there are a lot of pieces of work. Some

of those studies have attachments to them associated with comments from various parties.

When that happens, it is commonly the case -- in fact, I'm not -- I'm not aware of a single counterexample where there is not at least one party who says, you know, this is a very complicated subject and we really should wait to make any change until we study this further.

CHAIRMAN PICKETT: I would ask all of those online to please mute your phone.

DR. SCOTT: So let's study things further; let's wait until there's more information. That's not always wrong. But one of the things that's very important for all of us, I think to be critical of or question, is whether the information or the study that might occur is likely to actually provide insight that would change the decision. Because it will always be the case that there's much more that could be done, much more precision that might be gathered.

And the problem is, it's a multidimensional problem. It's certainly much more than three dimensions that we're worried about.

Okay. So costs. And the remainder

of this presentation -- or talk, I want to talk about costs of transcos. A little bit of costs about an electricity reliability organization; a little bit more about costs of centralized dispatch, some sort of organization to manage that. And next time we visit we'll talk about benefits of some of this stuff.

So the focus primarily today will be costs of a transco, and particularly we'll talk about new transmission costs.

So in terms of transco costs, if you -- there are, as you well know, at least three private parties; at least one of whom is in the -- representatives are in the room who have come to Alaska and suggested that they might help by investing private capital and bringing expertise to the table and maybe helping build some new transmission assets. And there will be a cost to that if that occurs.

And the reason for that, as you well know, is private capital tends to demand to need an equity return, which is riskier; needs to be compensated, equity investors expect that. Along with equity returns come tax burdens associated with income on those returns.

Potentially there are issues around the cost of debt.

Right now you've got member-owned co-ops who've got access to very inexpensive debt. Fortunately that's the case; and we've all benefitted from that, provided, in part, by the federal government; but -- so we're going to talk about that a little bit in terms of the costs of private capital as opposed to public money in the form -- especially in the formation of a transco.

We're going to talk a little bit about the distribution of costs if you were to form -- if a transco were to form in the Railbelt -- distribution of costs among the parties; and then we'll also talk about potential costs of new transmission assets themselves to ratepayers, what -- what that burden would represent.

So, some costs of a private transco. Well, these are stylized -- highly stylized futures; and there are intermediate cases. There's a business as usual case where you've got disparate transmission ownership; multiple balancing areas; multiple and pancaked transmission tariffs -- I think you're familiar

with this -- and those transmission tariffs tend to inhibit the efficient dispatch of generation units across service territories. There's -- so here -- then we can jump to the polar case where imagine we had a private transmission company which was -- encompassed -- had a CPC end that encompassed much or all of the Railbelt and it owned transmission assets.

And, indeed, in terms of modeling runs that we're going to talk about in just a second, I envision a case -- again, this is a polar case in which all of the functionalized transmission assets are essentially rolled up into a transmission company. And that's what they do, they're transmission.

People -- the existing transmission assets are, in some way, handed over -- not necessarily in terms of ownership, it could be a lease arrangement; it could be actually just functionalized control even -- but are sort of handed over to this entity which owns or holds the transmission assets and balances utility loads within reliability constraints and provides -- the one thing that a transco will do -- it's not the one thing -- but one of the things that a transco

would do and would be a transmission only company -- it wouldn't own any generation assets -- is that it would provide a business bottle -- model for building new transmission assets.

Right now when you have a transmission asset that spans more than one service territory, as we'll see in a little bit -- actually, towards the end today -- we -- we're talking about an asset that provides shared benefits; and because those benefits are shared and the benefit levels that each party receives are uncertain, it's a function of future conditions, it makes it difficult to agree on who's going to put in how much money and who's going to own what rights to those assets.

And that's especially the case if those assets provide benefits to parties outside the deal in terms of reliability and so on, which is always the case -- or just about always the case. Just about.

As modeled here, we're going to look at postage stamp rates throughout the Railbelt. And the reason for doing a postage stamp rate is because it creates opportunities for

maximizing, most efficiently, the operation of the generation assets that you have.

If, in essence, transmission costs are treated as sunk because they're going to get paid for no matter what and we have a way of distributing the cost of that sunk asset, then it liberates opportunities for figuring out what should most efficiently -- which generation asset should most efficiently run throughout the Railbelt.

There are intermediate cases that will be considered. I'm not endorsing anything; I'm just trying to provide some structure around what is sort of in the background of what we're going to subsequently see.

So some costs of a private transco. We talked about this before. Private costs of capital tend to be greater than member owned or municipal capital. And postage stamp rates, as contemplated here, may increase transmission costs to my customers. They also might decrease transmission costs to my customers. So there will be winners and losers on the transportation piece potentially.

And the distribution of those costs

and benefits is -- very critical issue for thinking about how we might move from here to there.

Okay. So what are the current costs of transmission? We don't have right now -- or until recently, costs of transmission, for the most part, weren't a subject that you guys had to deal with because you had service territories and everything was just rolled into one.

Chugach Electric, under contract, provided electricity to distribution companies and both Homer and MEA substantially; Golden Valley did the same. But those transmission costs were just rolled into the cost of service that people paid.

Again, as you well know, this has gotten complicated recently. So part of the complication for you, right, is this -- in the cases in front of you, I would suggest that there is at least an incentive for parties to work to shift cost responsibility on to other parties for assets that provide some degree of shared benefit. And because of that, it -- things get sort of muddled.

So what I tried to do -- and it is

artificial -- unquestionably, it is an artificial thing to do, but it's the only thing that's sort of -- as an outsider that's relatively easy to do -- is I relied upon the existing utility FERC Form 1 filings.

And in those FERC Form 1 filings that they might go to the Commission, each of the utilities functionalizes their assets across generation, transmission distribution, and other stuff. Everything that the utilities themselves describe as being a transmission cost or a transmission asset in that functionalization, which is, as I understand it, essentially everything of 69 kV and above is what I grabbed in terms of assets and costs.

So we went through and we pulled out numbers from those filings. And then -- so that's how I would get operating expenses for those functionalized transmission assets; and that's how we got maintenance expenses for those functionalized transmission assets, and that's how I got net book value for those functionalized transmission assets.

In general, I assumed that the costs of capital for transmission assets was

basically the utility's cost of capital as a whole. There's not a separate asset that was financed separately. That may or may not, in any given case, be true; but that's as close as I could possibly come.

And I took a particularly crude and simple way of getting at that cost of debt, which is to assume, essentially, based on the FERC Form 1 filings, I took actual interest payments recorded for the year and I looked at outstanding principle and just did a simple division. You can get more complicated than that.

For our purposes, and for purposes of sort of understanding the dynamics in play, there's really not much need to get -- for increased precision. Because at the end of the day, we're trying to get a sense of things.

In general, I adopted current TIER or ROE. There's an exception; and that is, for Chugach Electric, I boosted the TIER on transmission assets to 1.3 instead of 1.1. And I did that -- it's totally artificial; and you people can beat me about the head if they want, I'm used to it -- Chugach's TIER for transmission assets, as I understand it, was set by this

Commission substantially lower than 1.3, something like 1.1; and TIER for the rest of their assets is supposed to float such that on average they have an overall TIER of 1.3.

The 1.1 TIER for transmission assets makes -- arguably -- well, is a product, as I understand it, in part, of proceedings in front of this Commission historically having to do with previous long-term contracts between wholesale customers and Chugach, which I have not read carefully and don't dispute the merits of the decisions that were made.

But it strikes me as a little peculiar, at least internally logically, consistently given the rest of how I'm modeling stuff, to provide a separate return on transmission assets for one party but not for the others. Because as you'll recall, right, for the cost of debt, I'm just taking the imbedded cost of debt and spreading it out over all assets for the other parties.

So I'm going to do essentially, more or less the same thing for Chugach. I'm relying only on the year-end filings from 2013. When I had time to pull the data, that's -- the

FERC Form 1s were available. I believe that you might have a new slew of them that's complete now, but I'm not sure. So this is dated.

There's been a certain amount of -- significant spend in the last calendar that -- in the last calendar year. And in general, I'm assuming that transmission assets have got a useful life of about 50 years. And that is a little aggressive. So it's going to tend, in general, to produce somewhat lower numbers.

So the 50-year asset life really is only going to show up and make a -- well, so I assume a 50-year aggregate asset life for transmission assets -- I don't assume the existing assets are going to last for another 50 years.

Okay. What I do is I basically take a ratio for -- I determine remaining useful life by taking a ratio -- essentially looking at the percent of net book value of plant in service plus CWIP -- and that percent of 50 years is remaining useful life -- for coming up with costs of service. I ignore the vast complication that you all have been wrestling with in terms of worrying about T-1 through T-7 services.

And in general, what I do is for

each revenue requirement for each utility for transmission, I come up with a -- an indicative sort of cost of service by dividing only by native load. That's not a tariff.

I'm not trying to handle any of the problems associated with the value of shared assets or how much power actually gets wheeled. There's one exception; and that is, for Chugach, I divide their transmission costs also, rightly or wrongly, by billing determinants associated with their wheeling of Bradley Lake power because they have an existing agreement, which requires them to wheel power over the -- their system.

And so that wheeled power counts as part of their billing determinants. I've scratched my head about that; I'm not sure it's necessarily the right way to go about doing it. These are, really, at the end of the day, kind of -- in some sense, arbitrary numbers.

What I'm trying to do, in part, is once I generate a revenue requirement for each utility, get a sense of their interest in and need for -- well, their interest in how they would look at dividing up those costs potentially differently. Chairman?

CHAIRMAN PICKETT: I think this might be a good point to entertain any questions Commissioners have on the first 11 slides before we get into the utility specific numbers. So one question I have is with the charge that the Legislature has given us, you know, whether creating an independent system operator or similar structure for the electric utilities in the Railbelt areas, the best option for effective and efficient electrical transmission.

And one of the options -- I'm not sure how to articulate this -- is sort of the status quo, perhaps, with mechanisms to incentivize or encourage tight power pooling agreements or even loose pooling agreements, like in the western interconnect. Could you address that?

DR. SCOTT: Poorly. There are lots of arrangements that might be made to move from one system to the next. If you change rules -- change right -- which is to say, if you change rights and responsibilities -- or rights and obligations, you will change the available equilibria.

So there is no question that one

could create a system in which -- I mean, the utilities between themselves today trade power. They do it all the time. And so today we're certainly in a circumstance in which there are bilateral agreements made around the generation and sale of power on a wholesale level.

And say a loose pool, which some have advocated, you could create relatively modest step-out institutions in which parties simply had somewhat less friction in their posting of available surplus power or needs for power and -- and the friction associated with -- so the friction associated with enabling those transactions might be reduced.

And if that were the case, then presumably there would be some reduction in overall costs. There will be arguments, for sure, that that is all that you need to do because, of course, the parties are doing everything they can always to ensure that their customers are paying the lowest cost of electricity. I think that's true. I think that's largely true.

I think it is largely the case that the parties are always working on behalf of their customers. But it's not the case that you have

the same set of possibilities necessarily with a loose pool as with a tight pool.

And I should back up for just a second, because we're tossing words around as if we all understand what they mean. And one of the things that I have been incredibly frustrated by and sort of hate this industry for is the use of very special words. And we get to have lots of arguments around what an independent system operator is or what a tight pool is.

And a tight pool's not a same thing as unified dispatch; or a tight pool isn't the same thing as economic dispatch or it differs in this way or, no, it doesn't, it's -- you know, so the problem is not only, do we get to argue about what things mean; what they mean seems to shift over time.

So if you're a knucklehead like me and you're not quite sure what the magic words mean, you know, you go and you do Internet research; and it's like, oh, okay, here's the definition. Then you do some more research, and here's another definition. And if they're five years apart, the meaning's have changed, even when used by the same party.

So when you asked about, well, is there another way of doing this tight pool or a loose pool or -- obviously there is; and to carefully understand the differences available we'd have to have a conversation about what we mean by particular words and phrases.

And then to understand consequences we could -- get to do a whole bunch of complicated modeling that people are going to disagree about.

In the case of a loose pool, what I understand to be a loose pool is -- it's been described by somebody in the room as -- as a Craigslist bulletin board in which we all post what we've got available for excess power and what we're willing to sell; and other people post what they want to buy in the market.

It provide -- it's a little more than an information sharing platform. Perfectly fine analogy, that's -- I mean, I don't care.

CHAIRMAN PICKETT: Other Commissioner questions or comments at this point? Before we move on, one of the challenges -- and I take to heart your comments on definitions and clarification of the terms being used, particularly with who we are charged to submit

this report to so there is an understanding of sort of the baseline common information and data we're working from -- but when you think about the electric utility industry in general, I think it's fair to say that, for the most part, inertia rules until it's knocked off by some externalities.

And, you know, as you've reviewed the various efforts and reports over -- just take the last 10 years, it's seems like one of the threads that goes through it is in the Railbelt we just have too darn many utilities. And that makes no flipping sense.

And if we could just get it together and get one, you could fire all the managers, with the exception of one set, and get all these efficiencies that would lower my rates. And how do you comment on that? I personally don't think you would see -- it'd be so infinitesimally small that --

DR. SCOTT: So you're anticipating the very last slide of the presentation actually.

CHAIRMAN PICKETT: I didn't look ahead.

DR. SCOTT: It turns out that if you aggregate the annual costs of the utilities in

the Railbelt, just looking at 2013 data, the overall costs of the system is stout. That's not a criticism; it's just an observation. It's north of $900 million a year, 2013. And that's a chunk of change.

I'm not talking about investment; I'm talking about the annual operating revenue which is received from ratepayers. It's a substantial number, right?

The State operating budget as a whole on the order of $5-and-a-half billion, so we're -- what is that, one six -- 18 percent of the entire State operating budget in electricity bills. $900-and-something-million.

So let's imagine we've got rid of all that gosh darn overhead and we only had one set of managers, what are you going to save? Couple million dollars a year maybe, ratepayers as a whole. Oh, gosh it's got to be more than that. I bet it's 3. Okay. So divide 3 by 900-and-something-million, it's nothing. Is it going to affect a rate? No.

CHAIRMAN PICKETT: I think this would be a good time for about a 10-minute break, and then we'll come back to your presentation and

continue.

(Off record.)

CHAIRMAN PICKETT: We are back on the record. It is 10:05 a.m. I believe Commissioner Rokeberg has a question or two.

COMMISSIONER ROKEBERG: Thank you, Mr. Chairman. Good morning, DR. SCOTT. Couple of just kind of technical-type questions. I -- sneaking ahead I see some numbers coming up; and I wanted to ask you on this particular slide, you indicated that you're using the billing determinants for Bradley Lake for determining the Chugach amount of transmission, you're looking at a dollar amount; is that -- or what -- or how are you breaking it --

DR. SCOTT: Just billing determinants, Commissioner. So --

COMMISSIONER ROKEBERG: Well, let me just -- let me finish my question, then maybe -- well, using a Bradley Lake billing determinants -- using something that's peculiar to the Bradley Lake contracts, particularly the service agreement, exhibit -- appendix A calculation, which removes the Beluga-MacKenzie provisions and also has a 90 percent cap, these

are peculiar to those contracts that are not reflected in the last two docketed transmission tariff rates approved by the Commission.

So I'm just wondering if that -- to make them more consistent, whether that's important or not in how you're doing this. Also understanding we have a limited period of time here to work with. So in that context, what is your response?

DR. SCOTT: Just to clarify, there's sort of two stages of what I'm doing. The first is a revenue requirement assessment, right. And for that, Commissioner, I don't pay any attention to any of the Bradley Lake arrangements.

Okay. So what I'm doing for purposes of generating a transmission revenue requirement utility by utility -- and let's call it a stylized revenue requirement, right, it's a stylized cost of service. It's meant to be indicative. Again, all I'm doing is looking at FERC Form 1 and what's functionalized there.

For purposes of looking at ratepayer impacts of those revenue requirements -- or step back a minute, it's not even ratepayer impacts, it's really a question of -- call it

political interest.

I'm using the billing determinants of each utility in their service territory. So I'm not trying to get into wheeling as a general matter, okay, because those are a function of bilateral transactions and are history bound.

So I allocate then cost based on billing determinants for -- of the separate revenue -- transmission revenue requirements on the billing determinants in the separate service territories, with the exception that -- for Chugach because they're required -- because their facilities are used for wheeling power to the various Railbelt utilities.

I have, somewhat arbitrarily -- and you could do this the other way -- and if you'd like to see results, I'm happy to take it out; it's not going to make a huge difference -- I've divided by those -- the Bradley Lake wheeled billed determinants. Then I have -- so the services agreement that you referred to has to do with the revenue side from wheeling, and I'm not addressing that here at all.

COMMISSIONER ROKEBERG: Thank you. Perhaps you can -- hopefully that was enlightening

to everyone. Perhaps you can help me later --

DR. SCOTT: Clear as mud. I'm sorry, about that.

COMMISSIONER ROKEBERG: -- right now. And I'm not suggesting you should modify it. I was curious about what it meant.

DR. SCOTT: Okay.

COMMISSIONER ROKEBERG: Yeah. And -- but what the impacts are. The only other question I have looking ahead is the -- where the incidents of the ownership or the costs of the AEA owned -- the Alaska Intertie falls in your -- where does that show up as far as when you -- we're looking at transmission systems here?

DR. SCOTT: It doesn't.

COMMISSIONER ROKEBERG: It doesn't?

DR. SCOTT: It does not. So the Intertie, as I understand it is -- in terms of its capital costs, is largely -- it's paid for. And right now there's ongoing operation and maintenance expenses, which are, indeed, paid for by the member utilities.

I haven't attempted to fold those in, they're paying for them today anyway. So I assume it's the case that the -- how the Intertie

gets handled -- I mean, it was an arbitrary decision you could say. Well, no, let's fold those in and address this all at once, including that -- or address that sort of on a separate basis.

So at the end of the day, I don't think it qualitatively changes the story at all, given that the costs of -- the costs of the ongoing activity on the Intertie are already shared according to preexisting agreements; and they're quite modest as you know, but then I --

COMMISSIONER ROKEBERG: Thank you, Chair.

CHAIRMAN PICKETT: Are there any other Commissioner questions at this time? And, Antony, before you get into slide 12, these are all FERC Form 1 numbers from 2013; is that correct?

DR. SCOTT: That's right.

CHAIRMAN PICKETT: Okay.

DR. SCOTT: The date is December 31st of 2013. I mean, they're obviously filed in the spring of 2014.

CHAIRMAN PICKETT: So a new transmission that has come in will be picked up in

the '14 and '15 --

DR. SCOTT: That's right.

CHAIRMAN PICKETT: Okay. Please continue.

DR. SCOTT: So this is just a snapshot in time. There's a bunch of stuff coming online, as I understand, that MEA is going to need to make a bunch of investments or is in the process of doing that. To the extent that that's not already -- it's gone -- you know, it's not in here. So these are just basically numbers lifted from each of the utilities from the FERC Form 1s.

First thing to note is there is quite a lot of functionalized transmission investment that's been made over the years. These are original cost numbers. It's over $500 million.

I thought I'd point this out because sometimes there's a perception that, you know, these utilities, they just go to the State and they ask for money for everything; they haven't actually invested anything anyway. And that's not really true. They haven't made substantial investments over the years, especially within their service territories.

Remaining net book value on those transmission investments is about $300 million. That's about 16 percent of the total net book value on the utilities' books. So of the total net book value, it's only about -- 16 percent is tied up in transmission.

Why does that matter? Well, it matters because transmission is a relatively small share of the overall pie, right. In terms of what people are paying in their rates, transmission is a small share of those costs.

From the outside, looking at how vicious the fights appear to be -- I just read stuff, that's it; and I don't read it all -- but the fight's about transmission costs that are in front of you. From my perspective from the outside, you know, they're hard fought. And yet the stakes in the larger scheme of things are modest, I would suggest.

So if Railbelt-wide on a total basis transmission is about 16 percent of overall capital investment, it's distributed unevenly, right. Chugach Electric at the end of 2013, roughly 23 percent of their net book value was in transmission; GVEA, about 18 percent of their net

book value was in transmission; and the other utilities are all less -- less than the average, obviously. Just looking at that it tells you something.

People are going to approach the subject of changed institutions around transmission and who picks up how much differently based on where they sit today. So these are cost of service inputs basically lifted from the FERC Form 1. So, you know, these are the things that I'm working with.

Again, going back to Commissioner Rokeberg's question. If you were to look at only -- only at Chugach native load, it would reduce that by -- I'm thinking -- more than 15 and less than 10 percent, something like that. Sorry, more than 15 and less than 20 percent. Excuse me.

So take those inputs and put them into a traditional, sort of cost of service model tree; see what balances is part of your rate base; just pretend its used and useful. That's what I did.

And in all of my runs I generated revenue requirements, both on a levelized basis; that is, generating nominal dollar costs for each

and every year that are equal, as well as traditional costs of service basis.

The reason why I did things on a levelized basis was to help enable comparability once we got to thinking about and discussing transmission asset additions; because it gets just hard -- there's too many moving parts and it gets hard to compare things across time, but -- so I did it two ways.

And what we see is that on a traditional cost of service basis, if you take a composite of the utility-owned assets, the overall Railbelt-wide revenue requirement comes in at something less than $38 million. As a percent of the total Railbelt revenue requirement, it's a -- just about four percent.

So broadly speaking, if you pool everybody together, roughly four percent of the costs on the collective Railbelt electricity bill are tied up in trans -- existing transmission assets. If you're trying to get a sense of scale, right, it's more than that for Chugach Electric.

Now, again, I'm not saying these are actual rates that are borne by the native load customers. Chugach, if they're looking out for

their member owners and working as hard as they can to shift as much of those costs off to other people -- legitimately, of course -- but that's what you would do. Not casting aspersions on it by any means.

Golden Valley is pretty darn close to Railbelt-wide average, they're a little high; and you can see ML&P, they're less than three percent; Homer's less than two percent; MEA is way under.

Now, again, all of these numbers are influx, right. I expect MEA's number is going to come up significantly as they make additions in infrastructure to help accommodate their new plant and so on. But snapshot in time, there's where we are.

So obviously this is going to tell us something, I think, about where everybody's interests are going to be in terms of doing anything different on the transmission side -- cost side alone, right. There's another side of the coin; but we're not going to talk about that until -- well, next time. We're not going to talk about it now.

So if you were to have -- so if you

were to have a composite Railbelt-wide transco and you were to redistribute the existing assets into a postage stamp rate, okay, such that everybody paid on -- and in this case, I'm doing it on a kilowatt hour, you would probably allocate it in a more complicated way where you did it on demand, right, relative demand; but I didn't want to get into arguments about consequence versus non-consequence system peak and blah, blah, blah; where you've got ratchets or not -- so I just went straight to per kilowatt hour, right. Kilowatt hour, kilowatt hour.

So what you would see is, if you went to -- directly to a postage stamp rate, the -- in terms of, say, pooled costs, Chugach Electric would see their overall pooled costs drop by eight-and-a-half-million bucks or something like that for transmission.

Now, that's not dropping from where they are now. I don't know how much -- and this, I think, maybe goes to Commissioner Rokeberg's earlier question. I could not tell you today because I haven't gotten into the complications around it -- how much of Chugach Electric's existing transmission assets are currently being

actually paid for by other -- other member utilities or ML&P or what have you, in the Railbelt.

So in terms of a difference from average, this is overstating the differences because all -- for -- compared with the status quo. Because right now they're already able to collect some of their costs from -- of their transmission system from MEA, and indeed from any members -- a beneficiary of the Bradley Lake agreement. So this is -- again, we're overstating differences from today's status quo.

Golden Valley, again, if you were to have truly pooled costs, their transmission costs responsibility would drop some; little teeny bit. Not a lot in the overall shape of things. Homer's would go up; MEA's would go up; ML&P's would go up.

These numbers are not accurate, again, if you're trying to compare against the status quo. These are numbers which are compared against the division of costs as I laid them out.

So this is a little bit of a mental exercise around thinking not, how do we move from here to some place else; but in thinking about

moving what are people's interests potentially, right. That's what this is meant to get at. It's not meant to get at the actual exact transition costs from where we are now to where we're going. Because that's complicated, right.

Then you have to get into ratemaking stuff about where we are now and what it should be and interim rates, and I'm trying to avoid that.

So what would it mean to customers? So, again, in some ways I think we've got a worst cost circumstance in terms of thinking where -- about moving where we are now. What would it -- what would it mean for a residential customer?

Let's imagine we've got residential customers -- and I don't know if this is accurate; I'm sure it's not, and it's going to differ from one utility to the next -- but let's assume that monthly consumptions on the order is 600 kilowatt hours.

Were you to go to a postage stamp rate, the postage stamp rate for the composite utility asset would be on the order of seven-tenths of a cent. Chugach Electric's current rate -- it's not a rate -- their current

native load per kWh, potentially cost burden if they can't get anybody else to help pick up the tab, is on the order of 1.2 cents per kWh; Golden Valley's on the order of eight-tenths of a cent, little bit higher.

So if we went to a postage stamp rate, Chugach Electric's responsibility per kWh might drop by as much as half a cent. And that would show up on -- and -- well, and then for -- for Golden Valley, it's almost a tenth of a cent per kWh; for Homer, you're looking at potential increases of as much as two-tenths of a cent per kWh; for ML&P, maybe as much as four-tenths of a cent for kWh.

And so the impact on monthly bills shows up -- sorry, let's see -- yeah, okay. The impact on monthly bills shows up on the right-hand column.

And, you know, you're looking at -- for Chugach, on the order of $3.20 cent for a residential customer indicative; for Golden Valley, maybe they benefit by as much as $0.50 a month, and the other utilities you're going to see modest cost responsibility increases.

I say "modest," maybe that's not

fair. It's less than the cost of a latte at Starbucks; but Lord knows, many of us can't afford that. So, I mean, this is real money to real people.

I'm not trying to trivialize it. But in the overall scheme of things in terms of the utility bill, it's not massive. Certainly much less is involved than in the changing costs of hydrocarbons from Cook Inlet.

CHAIRMAN PICKETT: Just a quick question. As you look at the various utilities, MEA sort of stands out; but isn't it fair to say that transmission costs are embedded in the all requirements contract that MEA has had with Chugach Electric until recently?

DR. SCOTT: It's absolutely fair to say. They have been paying for transmission costs historically; they're paying for transmission costs right now associated with some, you know, issues that have been live before you recently.

So the movement for -- that MEA would see given a transition to a transco postage stamp rate is overstated here. This is a worst case kind of a story; because indeed, they are currently picking up transmission costs from

Chugach's system. They don't like how much they're paying right now; they think they should pay less, but they are paying now.

So setting aside, you know, the merits of what they should or shouldn't be paying; they're paying something now. So this is really -- I mean, in a world in which MEA paid zero for Chugach's system, that's this world.

The world in the -- where they pay zero for use of the Chugach historical assets is -- is more or less the world that you're looking at here. That's not the world that they're in. They're paying something; they think they should pay less, Chugach undoubtedly thinks they should pay more. It is what it is, right. That's not an argument about efficiency; that's an argument about distribution.

So, again, worst case sort of story in terms of the costs for change. So let's look at the costs of having a private party enter the scene, perhaps owning these collective assets -- or at least taking control of these collective assets at a cost, injecting equity into the system for the right to do that; that is to say, paying incumbent utilities for their transmission assets

for an ownership share in those transmission assets.

Now, the details around how that would actually work are complicated; and it's tied up in bond covenants and rural electric requirements and so on. So actually, a transmission would be effectuated with a private party, almost certainly it would be a process; and it would not look like this overnight, indeed if -- if it ever did.

I mean, you could certainly imagine a transco coming in and they would lease the assets. You can imagine a private party coming in to -- to be a transco, and they just operated the assets. But in a world in which we imagine them buying the assets, the most sort of expensive world, how bad would it be?

So under the current system with composite utility -- existing utility-owned assets, I've tried to suggest that the -- if you spread those costs out over every kWh in the system as a whole, it's on the order of seven-tenths of a cent for transmission service.

If we assume that the transco was an equity investor and they had a mix of debt to

equity of, say, 60/40; that is, they -- they injected about 40 percent of equity into the system which went to the existing incumbent utilities, so the capital structure would change. But value doesn't change, but the capital structure would change. There's cost to that, right.

Now, all of a sudden the transco would pay Federal income tax; and the transco would also pay State income tax. And those taxes would show up in rates. And they -- the return on equity in this case is going to be considerably north in the overall return that the existing utilities need to earn on the value of their assets.

So I've just mapped this out in terms of, say, what an 11 percent ROE would mean in terms of rates; and rates would go up compared with the existing case by maybe a tenth of a cent. Roughly speaking, increasing the return on equity, increase by one percentage point increases the bill impacts by two one-hundredths of a cent per kWh.

So the big move is, bring in equity at all; it's not as big as I would have imagined

it initially. I -- it's about a tenth of a cent.

The risk associated with uncertain need to cover return on equity -- again, we're only talking about the existing functionalized transmission assets -- gets driven down to hundredths of a cent. What's the cost to a customer?

Again, under the stylized assumptions of, say a hundred -- 600 kWh consumption per month, well, that's more or less $0.60 a month on a customer's bill for having a private investor-owned entity that assumed the ownership and functions of a transco. It's not nothing. It's well short of a cup of coffee.

And, again, the risks associated with ROE being higher or lower are worth something; but they're pretty modest in terms of what shows up on customers' bills on the order of $0.12 per swing of one percent ROE.

I guess the point of this is, we -- from my perspective, okay; this is just me, and I'm not supposed to do this really because these are my values and not anybody else's -- but from my perspective, by itself thinking about overall global costs from the Railbelt system as a whole,

having a private party earning private equity returns is not a big deal. It costs something for sure, but the costs are modest. Quite modest. Not the kind of thing in general that I would expect ratepayers to show up in front of your Commission with pitchforks over. Could be wrong, but -- okay.

So that's the existing system-ish. And, again, this is -- the foregoing was meant to get a general sense of scale and what's at play.

I want to talk about new transmission assets, though, because that's where things potentially get considerably more expensive.

So the thing to stress first, though, is that in contemplating formation of a transco, it means nothing -- absolutely nothing -- there is zero implication for what will be built in terms of new transmission assets.

On a policy basis moving forward to try to encourage formation of a transco is not a commitment to any given transmission asset, period. I think that's worth stressing. If I had the ability, I'd underline it.

And the reason why is, you know, I

worked for 10 years at Division of Oil and Gas; I've seen lots of projects and lots of project proponents, and we tend to be enamored a bit of big infrastructure projects. And we -- we lead with the project first. We -- it excites the mind thinking about new stuff.

And then we start often -- it's a habit of mine -- we start thinking, oh, I know, we'll get that; all you need to do is create this set of institutions and it'll help you get that; or all I need to do is get some -- the State to pay for it; or all I need to do is get the State to guarantee this, that, or the other thing.

So I would just say, this -- this discussion is not about starting with transmission stuff that we want to build and then backfilling with given institutions. I think that is absolutely a wrong way to think about the choices in front of you. This is not about what should be built.

Ideally, eventually we get to a place where we have better institutions for figuring out what should be built. But I'm jumping the gun.

So I'm going to look at some

transportation infrastructure projects that were modeled by -- contemplated by the Alaska Energy Authority in their pre-Watana study.

And the pre-Watana study was motived, in part, by saying -- by asking the following question: So if we build a dam, we're going to need to get the utilities to buy the power. And what they're willing to pay for the power is going to be a function substantially of how reliable -- how much they believe they can count on that power.

And right now, the existing system's ability to handle the amount of power that would be produced by the dam is somewhat constrained. So let's figure out how to -- what would be needed, at least cost, to ensure that power from the dam could be reliably counted upon by the various Railbelt entities.

And so they framed that up by saying, well, how do we ensure N -minus-one reliability of the transmission system, so that Watana power looks quite valuable, can be counted on?

And in the process of going through that engineering exercise there was a -- my read

of it anyway -- this is my read of events and motivations -- but there was this really kind of cool thing that came out, which is that the pre-Watana transmission infrastructure may pay for itself in terms of benefits associated with economic dispatch; that is, if you had increased levels of transmission infrastructure, you could take your existing generation assets and run them more efficiently for providing goods and services for the Railbelt customers as a whole; and by golly, this would be a winner going away.

Because not only -- even if Watana would never get built, even without Watana power, not only would ratepayers ultimately receive a benefit in terms of what their bills look like; but they'd also have substantial increased levels of reliability because the transmission grid as a whole would now be at N-minus-one. And it's not even remotely like that now.

And so this looked like a win, win, win. It's a win for reliability; it's a win even without Watana; and then if you do Watana, it's absolutely a win because you got to have it.

This last surprising finding that the savings associated with economic dispatch

would more than pay for the upgrades in transmission infrastructure is something that we're going to look at next time we get together. It's the other side of the coin, right. We're -- in terms of benefits. Right now we're only looking at costs.

So we're just going to talk about costs of service now. But again -- so this is just a lens to think through what a transco could potentially liberate. I said before, right, transmission is, to a significant degree, a public good.

Once inter-utility transmission is constructed, multiple parties benefit from it. The FERC, in various orders, has noted repeatedly that this public good aspect of transmission tends to lead to underinvestment in transmission because there's incentive to wait for the next guy to do it.

If you have a transco, you would solve that problem because there would be one entity that would shoulder the costs and capture the benefits on enhanced transmission.

So this was -- these are copied and pasted from the pre-Watana study. But they

imagine what the base system looks like in 2020, and then they look at a proposed system with a number of transmission upgrades.

So this a picture of what things look like on the northern half. We're basically twinning the Intertie, upgrading some substations. And so on the -- the northern part of the vision, twin Lorraine to Healy, twin Healy to Fairbanks, upgrade the substations.

What does that cost? It's not cheap. In 2012 dollars, on the order of 388 for the Lorraine to Healy section; for the Healy to Fairbanks, it's another 107 million. Together we're pushing almost $500 million of investment in 2012 dollars.

One of the things that doesn't exactly leap off the page of the pre-Watana study is that those -- that program of construction would take a while. And, indeed, the Lorraine to Healy project would take, more or less, 10 years; about four of which would be involved in regulatory processes and design. The Healy-Fairbanks goes somewhat quicker, about five years, two and a half of which is involved in regulatory process and design.

These obviously, to some degree, could happen at the same time. Although you probably wouldn't want to start on -- on the Healy-Fairbanks before -- well, you might.

Anyway, so the time dimension is a big deal because when the cost benefit assessments were done -- and there's lots of good caveats in the pre-Watana study -- but when the cost benefits assessments were done, they were looking at current costs of construction as measured in 2012 dollars, rather than cost to consumers at the time that the investment would be providing potential benefits. And it's that latter question which I'm going to turn to in what follows.

I'm interested in the ratepayer impacts of such investment. I think in the case of the pre-Watana study, they weren't particularly focused on this; maybe in part because there was a contemplation that, well, maybe this would get funded by the State of Alaska through the legislative appropriation process. We're poorer now; and so, you know, prospects for that are maybe more dim.

But I would also point out -- I can't help myself -- I would also point out that

the concept of State funding for an investment like this in the Railbelt strikes me as questionable.

If it makes sense to do and you have an institution that is capable of going to the market to raise the capital to do it, using State funds is really about -- you talk about cost causer/cost payer, that's really about having non-Railbelt residents of the State of Alaska pay for Railbelt benefits. That's just rent seeking, and it's not necessary.

It's not necessary because there are business models out there that allow transmission infrastructure to get built.

I'm not suggesting necessarily that the existing utilities, organized as they are, could take something like this on. I'm not suggesting that. They might be able to, given some work amongst themselves if they believed it was necessary. But we always face a little bit of problem with this stuff -- well, I'm jumping ahead.

I'll -- I've got another example where this is a little bit more compellingly drawn, I think. So let's think about generating a

revenue requirement for this northern stuff.

And the focus on the northern stuff is because when we get to the benefits discussion later on we'll see that benefits are especially -- can be especially attributed to constructing a more robust set of northern transmission infrastructure, benefits such as they are or may be.

So our base case assumptions is, I assume this is done by a private investor-owned utility transco without State help in our base case. In fact, without any State policy of any kind, other than encouragement and the eventual formation of a transco. I assume a 50-year levelized revenue requirement. 50 years might be too long, maybe 40 years is more appropriate. I'm certainly not trying to cook the books.

I've been advised by various people I've talked with to use one or the other. I can run it both ways, it's -- handle at the flick of a switch, as you know. It's pretty easy.

I'm assuming a 60/40 debt/equity mix, more or less conventional. I'm assuming an 11 percent return on equity and a cost of debt of about four-and-a-half percent. More are the last

current market conditions, given that this is a 10-year construction project, you tell me whether those are going to last. I don't know.

Could easily be more expensive than this, right, if we have a higher interest rate environment. Heaven forbid we go to deflation environment, and it'll get better still.

I assume -- and this is, I think, maybe the most conservative assumption -- I assume the project cost escalates at only two percent. That's more or less the federal funds target rate. General inflation runs at less than two percent, has been for a number of years.

Historically, obviously there are costs environments in which -- especially given a lot of cost pressure, those escalation rates can be considerably north of two percent. Some of the biggest risk on any long lead time project like this has to do with uncertainty around cost escalation; and it's uncertainty which is, practically speaking, extremely expensive to head.

Spend profile for ultimately generating rates in terms of calculating AFUDC and interest during construction is divided during the development phase, which we alluded to before,

that is, permitting and design, and then the construction phase, that matters a lot. You don't assume linearity across the two phases because it's not.

Fortunately in the pre-Watana study they did a really good job of laying out spend schedules and timing in the later part of the study -- in the full study in the appendices so that you can see what they project as the spend profile across the stages.

In terms of the year-by-year, indeed even month-by-month spend profile, I take more or less generic percent spent versus percent time schedules from Watana engineering estimates as a whole. Whether those are appropriate -- I mean, for a dam as opposed to transmission, nah, it's probably not.

On the other hand, I've compared the Watana spend percent -- spend percent time profiles with pipelines and -- which I'm much more familiar with; and they're pretty close. They're -- they just don't differ that much. It's not enough to make any difference in the overall story.

So then off that base case, I can

run several sensitivities. One is, well, let's imagine that somehow on a policy basis we encourage this to be a more levered project without changing the return on equity. You could do that. That was certainly something contemplated in the AGEA legislation that passed some years ago. Not -- is something potentially that the Commission could try to effectuate.

I'm not sure it's a good idea. I'm not saying anything about it one way or the other. But it could be done, and it's out there.

You could also -- the Legislature probably would need to do this, pass legislation allowing for transmission assets for the AFUDC. And by that it's a shorthand, both for return on equity and the return on debt -- components of construction expenditures not to compound; but instead to be paid for by current ratepayers. This is having current ratepayers pay for a future asset.

Now, this has been done in other jurisdictions, as I understand. And we'll see it makes a pretty substantial -- or a material difference in overall costs. And I model it just because it -- again, it's out there.

And lastly, I looked at potentially reducing the costs of debt through securitization where the State would issue debt which was backed by a on-bill -- by legislation mandating after Commission determination to on-bill charge.

This has been done, for example, in Hawaii to help fund installation of solar. It's being discussed, so I thought I'd look at it. The main effect of that would be to reduce the cost of debt.

I have friends who appear to be knowledgeable about these things who suggest that you might be able to reduce the cost of debt by as much as 150 basis points through this sort of securitization arrangement. So I looked at that as a policy.

So when you do that, you come up -- these are annual revenue requirements expressed in millions of dollars a year. So these are transmission costs that ratepayers would pay. So on our base assumptions we're looking at all-in on the order of $86 million.

Now, these are not 2015 dollars; this is money today. So this is way out in 2026 when this thing's fully operational, money today.

Now, that $86 million would be more -- as modeled here, would be essentially flat for the next 50 years. Long time. In effect though, it's getting cheaper and cheaper over time. So I didn't discount that back to today's dollars. That's money today.

If you change the debt/equity ratio, it reduces overall costs by around 7 million bucks. Not to be sneezed at. If you were to have AFUDC not compound, but instead have current customers pay for the financing costs during construction, that would have a bigger effect, on the order of $11 million on the eventual cost of service. And if you were to do some sort of on-bill securitization to reduce the cost of debt, that would reduce by, say, 6 million.

Now, all of these scenarios are against the base case; and they're not additive. I've not looked at any additive cases. Okay. These are just one-off separate policy scenarios.

So what would this mean for ratepayers? If you divide these costs by every kWh in the Railbelt equally -- which is not necessarily how you'd allocate the costs -- but if

you were to do that, you know, the simplest sort of postage stamp one could imagine, we'd be looking at something on the order of 1.6 cents per kWh in 2026. Today's dollars, that's something less.

The biggest effect, as we saw in terms of revenue requirement, shows up in terms of the AFUDC policy, more or less twice the size. But in -- in every case we're not moving the needle radically, right. We're dealing with tenths of a cent. Not saying that that doesn't matter, it does. But in general, we're looking at -- on the order of two-tenths of cent to a -- or the tenth of a cent.

So the benefits of any of this is on the order of $0.60 to $1.20 in 2026 per residential customer. Commissioner?

CHAIRMAN PICKETT: I think this would be a good place to take a short break for about 10 minutes. When we come back we'll see if there are any Commissioner questions on the northern transmission upgrades, and then move into the remainder of your presentation.

(Off record.)

CHAIRMAN PICKETT: We are back on

the record. It is approximately 11:12 a.m. I will turn to the Commissioners if there are any questions before we continue. So, Antony, please continue.

DR. SCOTT: Thank you. So this is the -- again, this is the analog; this is the southern part of the Railbelt. In terms of transmission infrastructure, both what exists today, more or less, and recommended upgrades in the EPS pre-Watana study.

Some of which are actually -- they're in this picture, but they're kind of part of that northern system in terms of the bottom part here of the -- of the Intertie. So, what?

Well, Bernice Lake to Beluga plus 25 megawatt BESS; Bradley Lake to Soldotna, upgrading that, and University-Daves-Quartz Creek. So de-constraining the Kenai, adding cross inlet redundancies and adding redundancies for the -- basically the connection to the southern part of the Intertie.

So how much? Again, just analog there. In 2012 dollars, 215 for the first, 72 for the second, 115 for the third. Somewhat shorter construction time and design. So seven years,

five years, and five years. Get into sequencing issues here around what makes most sense to do when. Are there going to be manpower issues as well? I haven't indicated the development portion of the schedule. But this is all in both development and execution.

So let's assume we did everything on the southern portion and the subsea cable has received a lot of attention and is somewhat controversial. I mean, are you telling me you want to spend $180 million on this? Whatever. I'm not -- I'm not going to discuss the merits, and it's well outside my bailiwick to try to do so technically.

But if you fold everything in and were to do everything in this program, you get a revenue requirement; and your base case on the order of $63 million. So it's somewhat less expensive than the northern portion. Producing an overall rate impact in 2026, dollars of the day, of about 1.2 cents in the base case. And then there are savings off of that base case, depending upon various policy measures that might be undertaken.

The savings are, again, on the

order of as much as maybe two-tenths of a cent, not quite, to something -- you know, to a tenth of a cent per kWh.

So let's talk about some additional upgrades that are identified in the study. And I want to talk about these in part because the Chairman has publicly expressed surprise at the results that were generated by the EPS study.

Looking at essentially reliability upgrades, substation upgrades, total costs for these are much more modest; they're on the -- combined they're on the order of $20 million.

And the claim in the EPS study is that there's a benefit cost ratio of making these investments that would cost on the order of $20 million, that is, north of 20. Now, that is pretty remarkable. North of 20? Are you serious? Like, what the heck is going on?

If we have benefits out there that have a benefit cost ratio of north of 20, why aren't they happening? Heck, let's have that. Let's say it's north of 10, my goodness, why aren't they happening?

The first thing to note is that unlike any of the other benefits in the study, the

benefits that are ascribed to these upgrades are not in terms of savings associated with the economic dispatch; but instead, are associated with increased reliability that consumers would realize. Reduction in the frequency and presumably duration, but certainly frequency of outages.

Last time we talked about reliability, so reliability is an unbilled value. There's nothing that shows up directly on the bill under reliability, right. And consumers have a hard time pricing that because there's not an easy market for it.

So benefit cost ratio north of 20, really? Why -- why isn't that happening? Well, maybe the benefits are overstated. Maybe it's the case that the non-billed value plug that is being assumed is really inflated. It might be. That could absolutely be the case. Hard to know what that thing is for sure. Is it overstated by a factor of 20? Unlikely.

I mean, there is a fair amount of literature out there on survey work that's been done on people's willingness to pay for reliability. But it's survey work, it's all

hypothetical. It's a lot like saying, what's your willingness to pay for a sea otter that's not oiled associated with a disaster in Valdez, right.

I mean, there's a lot of non-billed value surveys that were done to try to come up with values associated with environmental disasters. Happening right now in the gulf with Macondo, right. It might also be, though, that the -- the investments aren't happening because the benefits of making the investments are shared by multiple entities. After all, reliability is a public good.

So maybe it's the case that, yeah, the investment, it would happen in my service territory; but you are going to receive a substantial portion of the benefits received. And I've got no way to easily charge you for those benefits. I can take it to the RCA and try to go through a rate case, and maybe they allow me to fold it into a rate and maybe they don't; it's uncertain. Nobody knows the principles.

If I'm not sure I can get those benefits received by the next guy recovered in my rates, well, maybe I don't want to make the investment because I get maybe a third of the

benefits. And now instead of a 20-to-1 ratio it's actually more like a 6-to-1 ratio. And if the benefits were overstated a little bit, things start to fall apart a little.

It could also be because maybe -- maybe I don't want to pay for it because I can just step back and wait. We all agree, these are shared benefits. Let's get the State to pay for it. There's value in waiting to see if you can get the State of Alaska, rather than your ratepayers, to pay for it.

How much value is there? Well, again, I would submit that there's less value than meets the eye. Because what you're really talking about is getting non-Railbelt ratepayers to pay for shared Railbelt benefits for reliability. So you tell me the proportion of people who live off the Railbelt. It is a distinct minority of the State's population.

So it's -- I mean, at the end of the day, those public dollars belong to all of us. And you're really only gaining something -- you know, a portion of the benefit of having the State pay. Yeah, you don't have to get hell because you raised people's rates, so you don't have to

worry that political blowback. But that's a management set of calculations. Not saying that it's what's going on, but maybe. These are -- these are possible hypotheses for what's going on.

It's also quite possible that, you know what, everybody's busy. I mean, everybody is very busy; they're busy doing other important things. And so getting to this reliability thing, it's nice to have; but the lights aren't going out right now very much, so I'm going to put it off. Might be a perfectly reasonable decision. There might be more value for the company to do something else.

It's also the case that maybe I'm putting it off because insurance; that is, investments to ensure reliability are costly and it's a little bit like buying insurance, you know. Why have a certain cost when, after all, the disaster's not here, it's -- it's -- this is the problem with insurance, right. Right, young people, I sure am glad I didn't buy any health insurance because after all, I ain't sick. Made it through another month, saved on the premium; sounds like a pretty good deal. And certainly from a ratepayer perspective, that's what it looks

like.

If I have more or less good reliability and then you want to raise my rates to make an investment that's going to generate, what, reliability? I mean, you can certainly see a lack of appreciation because these are -- I mean, where the benefits show up in terms of how much more reliable the system is, highly technical, not easily translated. I certainly don't understand that stuff.

It's also the case that ratepayers, even if they really do want reliability, you've got no easy way of pricing it and making that known. Might be a mix of all of those things in various measures. And it also might be because there is no single party whose job it is to ensure that the system, as a whole, is reliable. It's a shared group responsibility right now.

So as we talked about reliability last week or -- I think it was last week, it's highly uncertain if you wanted to move to mandating some sort of reliability organization, what that would look like.

I mean, quite clearly you're not going to replicate the federal system; and there's

no need to do that. Multiple, multiple layers. And it would be very difficult to do even if you -- I mean, first of all, there's no need; and even if you wanted to, would be hard because we lack a fair amount of expertise, I think, in terms of the redundancy that -- that exists outside.

But if you were to have a mandatory system, I would posit the following, that a mandatory system that doesn't have any mechanism for enforcement maybe isn't mandatory. And so if a portion of what's involved in electric reliability involves following process, then you would probably need some sort of audit mechanism to ensure that process is being followed.

So what might that cost? Oh, heck, I don't know. I mean, I just guessed, right. Let's imagine 10 people, fully loaded costs on the order of $240,000 a year, highly qualified, trained people, kind of know what they're doing; Railbelt-wide, that's on the order 2.4 million. How does that cash out? Maybe $0.35 a month for a residential customer, something like that.

Would you need additional staff? Would you need an oversight? Probably. Hopefully, it's part of somebody else's job as

well. It's not free. And certainly in terms of merely hiring a bunch of people to do this kind of audit, not only is it not free, but nobody's going to be able to say, and here's the benefit you receive from that. You will never know if it generated any benefit at all. Certain costs, widely speculated benefits, you just can't demonstrate it.

But I would say this: Right now the current system is that if there's a violation of the voluntary reliability standards, the benefits for that violation are privatized; that is, the violator didn't assume some costs. And the costs of that violation, such as they are, are socialized; that is, the increased risk is worn by other members of the system and from a cost cause or cost payer perspective, as that phrase gets thrown around here, that doesn't make a lot of sense.

Now, it may make more sense than the opposite arrangement; it may make more sense than paying for some sort of audit staff. But I would say that if you had an audit staff of some sort, you would privatize the cost of process and result violations. And in -- and fines, if any,

associated with such violations, those benefits would be socialized; that is, spread out among the parties, which from an incentive perspective, makes somewhat more sense.

Now, again, is it worth doing something like this? I don't know. I really don't. But it's at least something to consider. So most of what we've talked about has been about costs. We talked about costs of transmission extensively, cost of an ERO; touched on cost of unified dispatch.

Two steps of costs. There's the ongoing costs of having some sort of unified dispatch, whether it's an ISO or a tight pool or, you know, some singular entity which is managing which generation assets on the system go when and how to operate them at least cost.

In 1998 Black & Veatch suggested that for staffing only, none of the upfront start-up costs associated with, you know, new buildings and computer equipment and so on, you'd need on the order of 11 people paid, at that time, at $244,000, 1998 dollars. If you trend that, assuming three percent inflation between now and then, you come up with -- in 2015 dollars,

something on the order of 2.6 million bucks.

And, again, on a Railbelt-wide basis, this is about $0.30 a month per customer, more or less. But, again, that's staffing only.

So in 2008, Black & Veatch, as part of the REGA study, did another -- took another run at this. And, again, kind of ongoing operations only, came up with a somewhat higher figure than this trended result; more on the order of $3 million a year. Again, excluding start-up costs.

One of the things that we did as part of our work for you is look at the costs as filed in FERC reports of every ISO that is under FERC's jurisdiction, which is everything other than ERCOT, I think, and looked at what those costs were. And you're got a range of different sizes of -- of ISOs and a range of different complexities of things that they are charged with handling.

But if you extrapolate down looking at cost as a function of the scale of the system being managed by the ISO, operated by the ISO, you know, it forms a trend line that you -- you'd be unsurprised to find that costs per kWh decline as

the total size of the system increases because there's a fair amount of fixed costs. But -- but the FERC costs have the benefit of including some of the fixed costs of that system. There's a disadvantage because we're extrapolating.

Our system is so much smaller than all of the other systems. But extrapolating and accounting for these economies of scale, you come up with a per kWh cost on the order of about a tenth of a cent, so all-in costs of an ISO up here in the range of .65, $0.70 per customer per month. Not nothing, something; so -- but in general, we've got three different measures here, and they're all showing up in more or less the same ballpark, I would suggest.

So just a couple slides to conclude finally. Railbelt utility operating revenue all-in at the end of 2013 -- you know, for the 2013 year -- calendar year is about $924 million in aggregate; return on capital is about eight percent of that total; return of capital in terms of depreciation and amortization Railbelt-wide is about 12 percent.

So return on and of capital of your existing system as a whole, transmission,

generation, distribution, overhead, A&G, that stuff, is about 20 percent. That's stuff you can do nothing about. The existing kit has to get paid for. You bought it, you buy it. I mean -- you know, you construct it, you buy it; you have to pay it for it.

So in terms of thinking about a more efficient Railbelt system, the existing assets, those are sunk; they're going to get paid for. 20 percent you take off the table straight away.

Railbelt transmission costs, all-in, are about $38,000,000. It's about four percent -- 4.1 percent -- whatever, who's counting -- of that -- that total mix. The generation portion associated with an O&M -- sorry, associated with a FERC Form 1, functionalized generation, if you just look at operation and maintenance of generation, about $290 million Railbelt-wide in calendar year '13. That's about 31 percent of your total costs.

This is not the capital costs of generation; this is the operation costs of generation. The four percent figure that I showed you before for transmission, that's all-in.

That's return of capital on capital, right; so -- but for Railbelt generation, just the -- the operation and maintenance costs are almost a third of your overall annual costs.

Fuel costs, which is part of the generation O&M, about $244 million in 2013. It's the lion's share of generation O&M. Of fuel costs alone, we're about a quarter of total utility costs. If you can deploy your generation assets more effectively, there's clearly opportunity for savings.

Now, going forward, these percentages will undoubtedly change. There's been a lot of new investment and certainly future fuel costs may be reduced from these percentages given more efficient machines that have been installed, better heat rates.

But I would say in terms of thinking about a more efficient system from a dollar perspective, the stuff that's easily measured, reducing fuel cost is -- is likely, at least I think, to be the biggest source of efficiency gains given the existing asset base.

How big are those gains? We'll talk about that next time. We'll talk about that

next time, so --

CHAIRMAN PICKETT: Are there any Commissioner questions? Well, thank you, Antony. And we will be continuing more on the benefit side in the model next week at another special public meeting, will probably be about the same duration as this one.

And before I close out this agenda item, I would like to remind everyone, if you intend to submit reply comments to our original order on the questions that were posited, we would like to have those in by this Friday because we will be taking those up -- the original comments and the reply comments and having some discussion on that on the 13th of May at the regular public meeting. So with that, thanks, Antony. We will close out agenda item number two.

I have no other business to come before the Commission this morning. Do any of the Commissioners have anything they would like to bring up? Seeing none, we will close out agenda item number three. Does the attorney general have need for an executive session?

MR. GOERING: No.

CHAIRMAN PICKETT: That closes

agenda item number four. Is there a motion to adjourn at 11:38 a.m. this morning?

COMMISSIONER PATCH: So moved.

CHAIRMAN PICKETT: Second?

COMMISSIONER WILSON: Second.

CHAIRMAN PICKETT: All those in favor say aye.

COMMISSIONERS: Aye.

CHAIRMAN PICKETT: Thank you for being here this morning.

(Off record - 11:38 a.m.)

I-15-001
Alaska Railbelt Electricity System

High-level modeling of
some costs and benefits of change

4/29/2015

ACEP
Alaska Center for Energy and Power

Legislative Charge

RCA should recommend:

Whether creating an independent system operator or similar structure for electric utilities in the Railbelt area is the best option for effective and ***efficient*** *electrical transmission.*

Efficiency

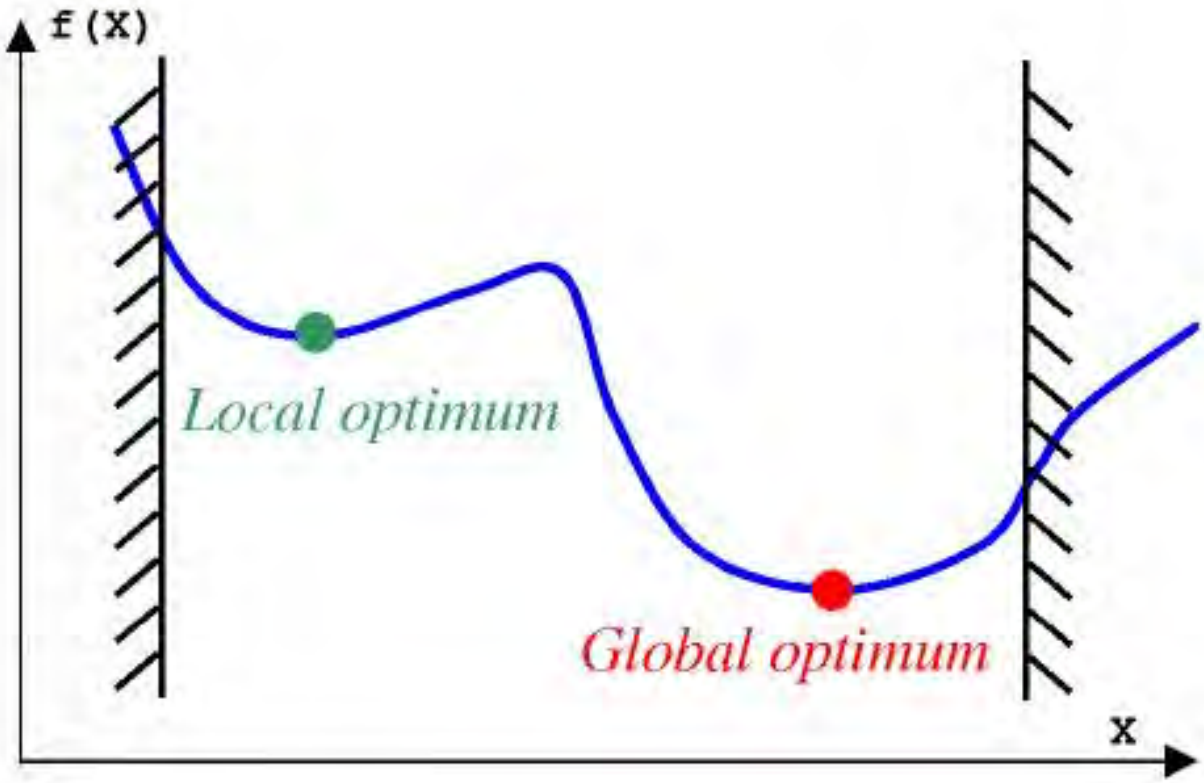
- Working definition:
  - State where there are no more changes such that:

    $costs < benefits$
- What efficiency is *not*:
  - Questions of cost allocation (what RCA spends most of its time doing)
- Natural focus:
  - What are costs of changes?
  - What are benefits of changes?

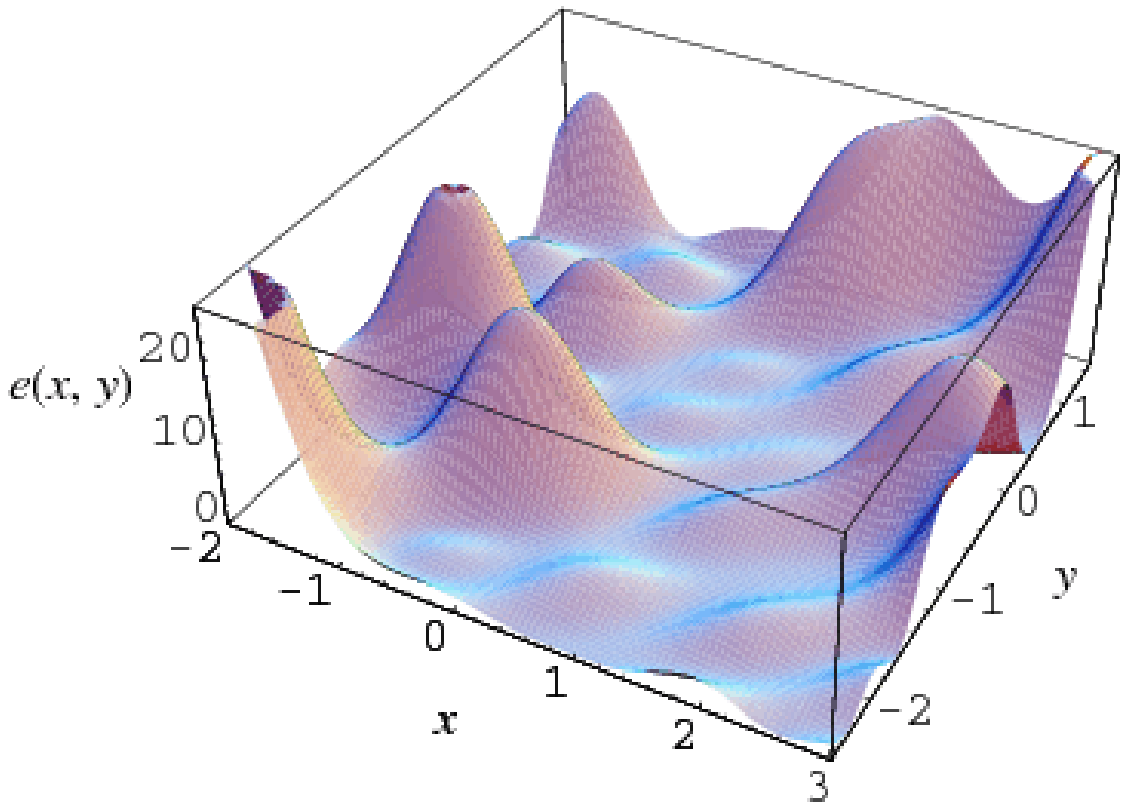
Policy Options for "Something New"

- If something new, what?
  - Transco?
  - Mandatory Reliability Organization?
  - Mandatory unified dispatch (ISO/RTO/USO)?
- Impossible to precisely assess efficiency without specifying what the change might be
- No proposal for change can be fully articulated at this stage

Efficiency: “Local” vs. “Global”



Efficiency: Multidimensional



Change

- Costly
  - Level
  - Distribution
  - Type
- Risky
  - May be bigger than anticipated
- Most easily delayed
  - Wait for more information
  - Study things harder

Costs

- Transco
  - Private cost of capital greater than member/ municipal utility capital
  - New transmission assets ($100s of millions)
- Mandatory Reliability Organization
  - New costs for ERO
- Unified Economic Dispatch
  - New costs for centralized dispatch
  - New costs for oversight board

Some costs of a private Transco

- Two **stylized** futures
  - Business as usual:
    - Disparate transmission ownership, balancing areas, pancaked rates, inhibited dispatch efficiency
  - Private transco whose function could be to:
    - Own transmission assets
    - Balance utility loads within reliability constraints
    - Provide 'business model' for building new transmission assets (efficiency, reliability)
    - Provide postage stamp rates throughout the Railbelt
    - Provide platform for economic dispatch

Some costs of a private Transco

- Private cost of capital greater than member/municipal utility cost of capital
- Postage stamp rates may an increased share of transmission costs to “my” customers
  - Winners?
  - Losers?

Current costs of transmission

- Procedure:
  - Rely on FERC Form 1 utility filings of functionalized transmission costs (69 kV and above) to generate COS
    - Assume 50-year aggregate TX asset life
    - Fold CWIP into net book value
    - Useful life set by NBV % of Plant in Service + CWIP
    - Assume embedded cost of debt = interest/principal
    - Adopt current TIER, ROE, capital structure (save for CEA, where TIER is boosted to 1.3)
  - Ignore existing tariffs (no T1-T7, no wheeling)
  - Use native load billing determinants (plus Bradley Lake wheeling for CEA)

Which utilities own transmission?

	TX Original Cost	TX Accumulated Depreciation	Net Book Value of TX	Total Net Book Value	TX as % of NBV
Chugach	296,010,860	142,330,077	156,670,175	670,476,624	23%
Homer/AEEC	50,370,053	21,169,390	34,681,923	407,165,211	9%
GVEA	142,244,513	69,124,785	73,244,241	411,863,359	18%
MEA	18,549,168	9,739,796	8,809,372	172,606,871	5%
ML&P	39,942,246	12,836,687	29,483,493	254,316,091	12%
TOTAL	547,116,840	255,200,735	302,889,204	1,916,428,156	15.8%

Cost of service inputs

	TX Depreciation Expense	O&M	D/E	Cost of debt	TIER/ ROE	Load (MWH/Year)
Chugach	5,632,403	6,213,423	74.96%	4.52%	1.30	1,527,381
Homer/AEEC	926,506	1,406,337	80.14%	3.05%	1.25	515,279
GVEA	4,109,823	3,504,220	75.14%	4.04%	1.79	1,253,161
MEA	496,713	18,794	72.79%	3.30%	1.71	723,955
ML&P	626,294	902,872	47.98%	4.51%	10.93%	1,047,470
TOTAL	11,791,739	12,045,645	72.91%	4.20%		5,067,246

Stylized Annual Revenue Requirements

Indicative Revenue Requirements - Levelized COS	2015	% of RR
Chugach Electric Association	18.96	6.2%
Golden Valley Electric Association	10.00	4.2%
Homer/AEEC	2.70	2.0%
MEA	0.64	0.6%
ML&P	3.35	2.5%
Composite Utility-owned transmission assets	35.97	3.9%

Indicative Revenue Requirements - Traditional COS	2015	% of RR
Chugach Electric Association	20.06	6.6%
Golden Valley Electric Association	10.65	4.4%
Homer/AEEC	2.55	1.8%
MEA	0.77	0.7%
ML&P	3.86	2.8%
Composite Utility-owned transmission assets	37.79	4.1%

Redistribution of utility costs?

	kWh Billing determinants	% Billing determinants	Pro rata share	Annual difference
Chugach Electric Association	1,527,381,000	30.1%	11.39	(8.67)
Golden Valley Electric Association	1,253,199,000	24.7%	9.35	(1.30)
Homer/AEEC	515,279,000	10.2%	3.84	1.30
MEA	723,955,000	14.3%	5.40	4.63
ML&P	1,047,470,000	20.7%	7.81	3.96
Total	5,067,284,000			

Redistribution of customer rates?

Indicative Native Load Customer Costs ($/kWh)	Current	Difference	Monthly "bill"*
Chugach Electric Association	$ 0.0124	$ (0.0053)	-$ 3.19
Golden Valley Electric Association	$ 0.0080	$ (0.0009)	-$ 0.53
Homer/AEEC	$ 0.0052	$ 0.0019	$ 1.11
MEA	$ 0.0009	$ 0.0062	$ 3.73
ML&P	$ 0.0032	$ 0.0039	$ 2.34
Composite Utility-owned transmission assets	$ 0.0071		

*Assumes 600 kWh/month for residential consumers

Costs of a Private Transco?

Indicative Native Load Customer Costs ($/kWh)		Monthly 'bill' differences		
	Current	12% ROE	11% ROE	10% ROE
Chugach Electric Association	$ 0.0124	$ (2.46)	$ (2.59)	$ (2.71)
Golden Valley Electric Association	$ 0.0080	$ 0.20	$ 0.07	$ (0.05)
Homer/AEEC	$ 0.0052	$ 1.84	$ 1.71	$ 1.59
MEA	$ 0.0009	$ 4.46	$ 4.33	$ 4.21
ML&P	$ 0.0032	$ 3.07	$ 2.94	$ 2.82
Composite Utility-owned transmission assets	$ 0.0071			
Composite existing transmission assets, IOU @40% equity		$ 0.0083	$ 0.0081	$ 0.0079

Under reasonable stylized assumptions, cost per kWh of a private entity is 1/10 of a cent per kWh, or perhaps $.60/month on a customer's bill

Meanwhile the "risk" or ROE being higher or lower is worth roughly 2/100 of a cent per kWh, or perhaps $.12/month on a customer's bill.

New Transmission Assets?

- Establishing a Railbelt-wide transco is NOT a commitment to new transmission!
- AEA Pre-Watana Study:
  - What transmission needs to be built to ensure N-1 reliability, needed to make Watana power most "attractive" to the utilities?
- Surprising finding:
  - Pre-Watana transmission may pay for itself, even without Watana
    - Something we will critically examine next time

AEA Transmission Upgrade Vision: Northern

Figure 3-1 Northern Base Transmission System

Figure 1-1 Northern Proposed Transmission System

AEA Transmission Upgrade Vision: "Northern"

- <u>What?</u>
  - Upgrade substations, twin Lorraine to Healy
  - Upgrade substations, twin Healy to Fairbanks
- <u>How Much (2012 $)?</u>
  - Lorraine-Healy = $388 million
  - Healy-Fairbanks = $107 million
- <u>How long?</u>
  - Lorraine-Healy = 10 years (4 yr reg + design)
  - Healy-Fairbanks = 5 years (2.5 yr reg + design)

"Northern" Transmission Upgrade Revenue Requirements

- "Base Case" Assumptions:
  - Private, IOU transco
  - 50-year levelized revenue requirement
  - 60-40 D/E mix; 11% ROE, 4.5% cost of debt
  - Project cost escalation of 2%
  - Spend profile subdivided per Pre-Watana study into development, execution phases and costs
  - Generic spend profile (% spend per % time) taken from HDR Watana engineering estimates, scaled
    - Impacts "AFUDC" (both debt and equity)

"Northern" Transmission Upgrade Revenue Requirements

- "Policy" Sensitivity Runs
  - Change IOU transco D/E mix (70/30)
  - Legislature could allow transco to collect AFUDC during construction
  - Legislature could reduce cost of debt through securitization

"Northern" Transmission Upgrade Revenue Requirement (nominal, 2026)

	Base	70/30 D/E	No AFUDC	3% COD
Northcentral Project Costs (Lorraine-Healy)	67.53	61.84	57.30	62.65
Northcentral Project Costs 230 kV upgrades (Healy-Fairbanks)	18.83	17.39	17.35	17.59

- "Base" per previous assumptions -> $86MM
- Change D/E ratio from base; 70/30 -> (-$7 MM)
- "No AFUDC", whereby current customers pay finance costs during construction -> (-$11 MM)
- "3% COD" reflects securitization of debt portion of upgrades -> (-6 MM)

"Northern" Transmission Upgrade Ratepayer impacts (nominal, $/kwh)

	Base	70/30 D/E	No AFUDC	3% COD
Northcentral Project Costs (Lorraine-Healy)	$ 0.0128	$ 0.0117	$ 0.0109	$ 0.0119
Northcentral Project Costs 230 kV upgrades (Healy-Fairbanks)	$ 0.0036	$ 0.0033	$ 0.0033	$ 0.0033

- Securitization benefits probably understated (combine with no Interest During Construction)
- Effects of 10% increase in leverage (RCA accomplishes?) about the same size as reduction in cost of debt (legislature accomplishes?)
- Collecting AFUDC from current ratepayers is roughly 2x savings of other measures
- Small monthly benefit ($.60 - $1.20 per res. cust)

AEA Transmission Upgrade Vision: Southern

Figure 3-2 Southcentral and Kenai Base Transmission System

Figure 1-2 Kenai and Southcentral Proposed Transmission System

AEA Transmission Upgrade Vision: "Southern"

- <u>What?</u>
  - Bernice Lk-Beluga HVDC + 25MW BESS
  - Bradley-Soldatna 115 kV
  - University-Daves-Quartz Crk 230 kV
- <u>How Much (2012 $)?</u>
  - Bernice Lk-Beluga HVDC/25MW BESS = $215 MM
  - Bradley-Soldatna 115 kV = $72 MM
  - University-Daves-Quartz Crk 230 kV = $115 MM
- <u>How long?</u>
  - Bernice Lk-Beluga HVDC/25MW BESS = 7 yrs
  - Bradley-Soldatna 115 kV = 5 yrs
  - University-Daves-Quartz Crk 230 kV = 5 yrs

"Southern" Transmission Upgrades Revenue Requirement (nominal, 2026)

	Base	70/30 D/E	No AFUDC	3% COD
Southern Projects revenue requirement	63.01	57.72	53.73	58.46
Southern Projects rate impacts	$ 0.0119	$ 0.0109	$ 0.0102	$ 0.0111

- "Base" per previous slide assumptions
- "70/30" changes D/E ratio from base
- "No AFUDC" change from base whereby current customers pay finance costs during construction
- "3% COD" reflects securitization of debt portion of upgrades

Transmission Costs
Southcentral Reliability Upgrades

- EPS identified Southcentral Reliability Upgrades
  - Fossil Creek, new 115 kV substation
  - Eklutna Hydro, new 115 kV substation
- Cost
  - Fossil Creek = $10.7 million
  - Eklutna Hydro = $ 9.8 million
- Claimed B/C ratio > 20
  - Based on value of unserved energy

Southcentral Reliability Upgrades: Why aren't benefits being captured?

- Benefits are overstated, *or*
- Reliability is a public good (other service territories benefit), *or*
- Gamble that the SOA will pay for it, *or*
- Each utility is busy with other things, *or*
- Insurance seems costly until you need it, *or*
- Consumers have no direct way of pricing it, *or*
- A mix of the last 5, *or*
- No mandatory-reliability overseer/authority

Costs of a Mandatory ERO?

- Highly uncertain as no model exists for what this might look like in Alaska
  - Enforcement audit teams?
    - 10 FTE @ $240,000 = $2.4 million
    - $.35 cents/month for residential customer??
  - Additional staff and oversight?
- Current state of affairs: socialize costs of violations, privatize benefits of non-compliance
- An ERO with teeth: Privatize cost of process/result violations, socialize benefits

Costs of Unified Dispatch

- 1998 B&V assessment, trended (staffing only)
  - 11 FTE @ $144K (1998$) =
    - $1.6 MM (1998$) or $2.6 million (2015$ @ 3% infl.)
    - Cost per kWh, Railbelt wide, is $.0005 or ~ $.30 per month for a residential customer
- 2008 B&V REGA study (A&G only)
  - $2,460 ($2008$) =
    - $3.03 MM (2015$ @ 3% infl.), or $.0006/kWh
- Cost of entity to do so (based on statistical extrapolation from national data, incl. *all* costs)
  - 0.0011-$0.0012 per kWh = $.66 - $.72 per residential customer

Efficiency in "current"-asset context: The Stakes

- Aggregate FERC Form 1 report data from 2013:
  - Railbelt utility operating revenue = $924,000,000
    - Return *on* capital (incl. retained earnings) = 8%
    - Return *of* capital (deprec. and amortization) = 12%
  - Railbelt transmission costs (all in) roughly $38,000,000
    - ~4% of total costs

Efficiency in "current"-asset context: The Stakes

- Aggregate FERC Form 1 report data from 2013:
  - Railbelt *generation* O&M costs = $290,000,000
    - 31% of total costs
  - Railbelt *generation* ***fuel costs*** = $244,000,000
    - 84% of generation O&M
    - 26% of total costs
  - Future fuel costs may be less with new machines
  - *Reducing fuel costs is likely the biggest thing that might be accomplished with existing asset base*

Questions?

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STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners: Robert M. Pickett, Chairman
Stephen McAlpine
T. W. Patch
Norman Rokeberg
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SPECIAL PUBLIC MEETING

May 6, 2015
9:00 a.m.

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P R O C E E D I N G S

(On record - 9:00 a.m.)

CHAIRMAN PICKETT: Good morning. This is a special public meeting of the Regulatory Commission of Alaska. It is Wednesday, May the 6th, 2015, at approximately 9:00 o'clock a.m.

With me on the dais are Commissioner Janis Wilson, Commissioner Stephen McAlpine; and I am Bob Pickett, Chairman of the Commission. We're anticipating Commissioner Rokeberg will be joining us shortly.

Agenda item number one is public participation. Are there any members of the Anchorage audience who would care to address the Commission this morning? Seeing none, is there anyone online who would care to address the Commission? Hearing none, we will close out agenda item number one.

(Commissioner Rokeberg joins dais.)

CHAIRMAN PICKETT: Let the record reflect that Commissioner Rokeberg has joined us. Agenda item number two, I-15-001, In the Matter of the Evaluation of the Operation and Regulation of the Alaska Railbelt Electric Transmission System.

I will now turn to Dr. Antony Scott

for a continuation of our discussion we spent several hours on last week. So, Dr. Scott, please proceed.

DR. SCOTT: Thank you very much, Commissioner. My name is Antony Scott; I work for the Alaska Center for Energy and Power at University Alaska Fairbanks. So this is your charge, you've seen this before.

Just to review from last time briefly; in the current asset context, FERC Form 1 data from year-end 2013 indicate that total Railbelt utility operating revenues on the order of $924 million, about 20 percent of that goes to capital -- return on and of capital.

Transmission costs come to about four percent of the total. That's all in operating return on and of capital maintenance.

Generation costs, on the other hand, are more substantial; more like 31 percent of total costs. And fuel makes up the largest portion of this, it's about 84 percent of your total generation costs of your total O&M generation costs.

So it's probably the case that reducing fuel costs is likely to be the biggest

thing that you might be able to accomplish with your existing asset base in terms of increasing efficiency.

So the focus is going to be on how to increase efficiency with an existing asset base today. In other words, the concept of economic dispatch.

In terms of the structure of what I'm going to present today for folks who are not fully familiar with how this might work, I'm going to first present three toy models or super simplified examples of conditions that can give rise to opportunities for economic dispatch for savings. And that'll take a little bit of time to work through just the arithmetic of those.

But -- then that will form the basis for helping to understand subsequent model runs. And what we intend to do is go through the ACEP base case for modeling dispatch on the Railbelt; compare that with the Alaska Energy Authority's base case, explain the differences, how we step from one to the next, and then get into some discussions around risk assessment of dispatch benefits possibly not being bigger or smaller than represented here in the base case.

So the thing to stress and seem like -- it seems like I stress this every time I discuss modeling, and I guess it's just because of my own history with modeling -- done a lot of modeling over the years -- there tends to be, cognitively, a great seductice -- seductive power of mathematical models in which you tend to believe that the answers that are generated mean -- are definitive. Let's put it that way. And, in fact, the world is a much more complicated place.

And so always it's the case that when we model we make a whole bunch of very stylized assumptions about a whole bunch of other stuff to look at; and they are focused in on a few dynamics, which may be very well captured. But nevertheless, are a small subset of the overall few dynamics.

The dispatch modeled benefits here are going to be a small subset and possibly the least important set of benefits from an enhanced overall Railbelt system. This says nothing about whether you should pursue policy changes.

But when -- we talked about costs last time; we're going to talk about benefits this

time. We're only talking about a very narrow slice of benefits, and it's the benefits that show up given the structure of the particular model that we're using.

Some of the more important benefits associated with potential new structures for -- or institutions for how the Railbelt is managed we'll touch on next time. But the focus today really is on -- on economic dispatch benefits.

So what is economic dispatch? For purposes here -- trying to avoid too many magic words -- but for purposes here what we mean is the use of existing generating assets to meet consumer demand at least operating cost.

So it's a -- in -- in a -- for an economist, it's a short-run concept. So you don't presume that you can change your transmission assets; that is, build new stuff or build new generation assets or -- like that. So economic dispatch is: How do you most efficiently use the stuff that you have to generate electricity at least cost?

Economic dispatch within the Railbelt as a whole is -- we'll see conceptually going to be different from economic dispatch

within each service territory separately.

In general, if you do economic dispatch over a larger area, you're going to get a different answer than if you do it over several smaller discrete areas. And in general -- and this is just a theorem for mathematics -- the fewer constraints that you have in an optimization problem, the more globally optimal the result will be.

In other words, the more you aggregate across space, the matching of supply and demand at every moment, the more you're going to -- able to wring out cost efficiencies from the existing asset base.

But also, it turns out to be the case, that economic dispatch needs to be thought of across time, which is to say, just like optimizing across space is preferable to sort of atomistically taking smaller regions, it's also the case that if you consider the deployment of assets dynametrically across time, you can achieve better results than if you're only worrying about economic dispatch one hour and then the next hour and then the following hour or day or week or year. So our toy example, so we'll play with

these concepts.

So, again, if the total cost of generation of providing -- and transmission and distribution of providing electricity to consumers is the sum of the capital costs and the operating costs, which they are, the capital costs, as we think about it here -- as I'm using these terms, at any rate; and -- and in terms of how these -- this is being modeled, it's assumed that the capital cost of existing generating assets are the responsibility of ratepayers in the service territory, whether or not those assets make any electricity.

So even if they sit idle 99 percent of the time, the capital costs still need to be picked up. By whom? By that ratepayer's -- sorry, by that utility's customer base.

If those assets run a lot and sales are made to another utility, well, margin may be made on those sales; and that's good for that service territory. But at the end of the day, the cost responsibility belongs with the native load customers.

And so for ratepayers, again, at the end of the day, what -- what ratepayers want

is the minimum variable or operating costs. The ratepayers, assuming that they only care about what shows up on their bill -- assuming that that's all they care about, which is a strong assumption -- and I may not be accurate in certain circumstances -- but in general, if -- if the total cost is the capital cost and the operating cost and the ratepayers have to pick up their native load capital cost no matter what, then at the end of the day, what do they want? They want the minimum variable costs.

And that could come from using the existing generation assets that they have or purchasing power from somebody else who's got lower variable costs.

So last piece of context here is, because transmission costs are essentially invariant with use, they don't -- they don't vary depending upon how much you're using the line. Transmission tariffs between two adjacent service territories tend to be -- tend to reduce the opportunities from gains from trade.

This is not unlike thinking about international trade between countries. If one country imposes a tariff -- different meaning of

the word but, you know, an import duty, for example -- in general, gains from trade between those two countries are reduced. And we see exactly the same dynamic in terms of thinking about the potential for gains from trade across utilities.

So that in general, one would see maximum economic dispatch opportunities if tariffs -- sorry, if transmission costs were covered as a fixed cost in rates that is not -- customers pick them up and they pay for them and they do not influence the cost of -- the variable cost of electricity. And we talked about that last time.

So here's toy example number one. And the arithmetic isn't very important, but the -- the basic concept is. So imagine -- this is a toy example, it's not meant to be realistic -- but imagine you have two utilities and they're connected by a transmission line; and assume that those transmission costs are sunk and do not show up in the variable cost of electricity.

And utility A's demand next hour's a hundred million megawatt hours, and utility B's

demand next hour is 130 megawatt hours and they both face the same cost of fuel and they've got different heat rates on their assets and different capacities.

For utility A what we see is, you know, their first generator is very efficient; it's the most efficient generator overall. But their second generator, generator Ga2 -- the A's for -- subscript is the A utility and 2 is the second generator -- is the least efficient.

And utility B's got three different engines and they all have exactly the same efficiency and they're sort of in between. Well, in the no trade case, in the case in which each utility is meeting their own needs ignoring issues of carrying spend for the moment -- taking the -- utility A is going to run its most efficient generator as much as they possibly can and its least efficient generator as little as they can.

Utility B, all of its generators have the same efficiency. And if I've done my arithmetic correctly, you get a total cost in the no trade case of $2,000. And this is where each utility's meeting its own needs with its own assets.

But let's say they pool their demand and they essentially pool their generating assets -- this is super simplified -- well, what you do now is you deploy the assets available across both utilities to minimize total costs.

And A's first generator runs flat out as before because it's the most efficient unit on the system. But its second generator, which is the least efficient on the system, turns off; it shut down, and B picks the -- the second utility picks up the slack. And when that happens -- sort of ignoring differences in heat rate over the load profile -- you get a total cost of -- in this case, 1,880, saving of -- something like six percent compared to the no trade case.

Now, this assumes, of course, that somehow the magic happens; there's savings to be had; the deals occur at the minimum cost, but this says nothing about what utility A ends up paying for utility B's increased output. So that question here isn't addressed because what we're doing here is simply minimizing costs overall for -- for meeting system needs.

And the subsequent PROMOD cases that we work -- in general, what we just do is we

assume that there are preexisting rules or tariffs for how savings are split. How those trades will take place, which is to say -- and -- and which is to say, they're just split basically -- the benefits are split 50/50.

And so of the $120 worth of overall system savings from this case to this case, $60 of that benefit goes to -- I can't quite say that -- they're split on a per kilowatt hour basis, not a utility basis. So exactly figuring out how this would work, I'd have to do some additional math, which I'm sufficiently sleep deprived; I don't want to do right now in my head.

Okay. So last time we were -- I mean, the last toy example we were looking at same fuel costs for both utilities for every generator on -- on the system. In this case, we have the same heat rates. But this time, the first generator's got very expensive fuel. Same heat rate, but very expensive fuel. So it runs on naphtha, say, for example.

And now all of a sudden -- then it's not a particularly good generator run, even though it's got a very good heat it's -- because the fuel is expensive, right.

So in the no trade case, the first utility's going to want to run that first generator as little as they possibly can. They have to run it some, but they want to run it as little as they can. And B dispatch is the same way that they did before. And overall system costs here have gone up. Why? Because fuel's very expensive for part of A's generation.

This doesn't look right. In this case where there can be trade across both utilities, A shuts down both of its units -- is that true? And -- yeah. And B's running all three of theirs. And we get substantial savings compared to the no trade case.

Now, if you think about this, this takes a fair amount of comfort, right. So I'm going to shut down everything and rely completely on you to generate all of the power that I consume.

Why on earth would I do that? Well, if I believe that the system overall was equivalently reliable and I had comfort that, indeed, you were going to make good on our agreement to generate for me, my customers are going to be better off.

So, again, assuming that the only thing that they care about is what they pay on their bill, which is a big assumption, the opportunity for trade, in general, produces favorable outcomes. But it still leaves open the question of how do you divide the savings? That remains up in the air.

And, indeed, if it's not sufficiently clear how savings should be divided and if the period of time is sufficiently short, sometimes trades don't happen because you have to dicker, right. You have to come to a meeting of the minds.

Now, what we're getting into here is the issue of transaction costs. Actual individual people are part of the system; and unless there are preexisting, pretty clear rules about how savings are going to get divided, the humans who are part of this system may not take full advantage of the opportunities because to engage is costly; and there are a lot of other things to do. You got to keep the lights on, for crying out loud.

Okay. Third toy example. The numbers have shifted a little bit. So what I

wanted to imagine here is a case where you had, like, a hydro resource. And the -- the thing about a hydro resource is, it's a stock, right. Given rainfall and snowfall, snow melt in a year, there is only so much power that possibly can be generated by that asset.

That means if I use some today, I can't use some tomorrow. It's the notion of opportunity cost, right. So the timing of when you use power might be important.

And this example is meant to sketch how the timing of how that stock resource is used. The hydro resource is used can -- economic dispatch needs to be considered and take place over time. The value of that hydro resource will differ depending upon how it's used.

So in this case I assume each of the two utilities has entitlement to the same amount of overall energy, 20 megawatt hours each from -- from the resource and that the -- the same amount of overall power. And I've -- but one of the differences here is that for each of them, their second thermal units, I assume there's a fixed cost associated with starting them.

So if you never have -- if you don't

have to start them at all, there's fixed costs associated with starting -- it's not quite fixed costs -- it's a -- it's a fixed operating cost that if you -- you can avoid if you don't start them.

So this is a -- again, suppose now that each of the two utilities says, you know, I'm not sure what's going to happen tomorrow; I'm just going to use a rule of thumb; I'm going to take equal amounts of my hydro resource each period. I have two periods; I've got 20 megawatt hours of total hydro energy, and I'll take 10 the first period and I'll take 10 the second period.

And if they apply that rule of thumb, you know, and you crank through the math, then you get a certain result, right; and total system cost ends up being, like, 3,720.

Both utilities have need to start their second unit, and it's unavoidable. So suppose now though the utilities are very good at communicating with each other; and they have extensive discussion, not just about what their load needs are this period but also what they will be next period; then they might well be able to dispatch the hydro in a different pattern where

they use more of it in the first period and simply don't need to start up one of those thermal units and less of it in the second period.

Overall system cost now has been reduced. Why? Because they've been able to avoid a start-up.

I mean, at the of the end day, the numbers don't particularly matter. What's being illustrated -- or what I'm hoping to illustrate is that you can optimize across time, as well as across space.

Some observations about this case. There's -- there's a lot more that needs to be shared. It's not just a question of, I have so much power available this period that -- you know, for this price; do you want it? I also need to share what my demand profile is going to be this period and next period. And we have to have a conversation about how together we might be able to come up with a favorable deal.

If the savings are relatively small, again, transaction costs may get in the way of making that deal happen.

The -- the -- but you can see in this case that the hydro power's got differential

value, depending upon how it's deployed. If it's deployed recognizing uneven demand across the two periods and it's deployed optimally, it has greater value than if it's just evenly used throughout the two periods.

There's an analogy here actually with transmission, which is -- at least I think -- which is as a non-power guy what was not totally obvious to me, there's a tendency -- or at least I have a tendency -- we'll talk about me -- I have a tendency to assume, hey, if a transmission line is fully loaded between two utilities in one period and in the next period, that means the potential gains from trade between those two utilities have been maximized, right.

Hey, it's fully loaded; we're trans -- we're trading power across a transmission line as -- and it's fully loaded; we can't trade anymore this period and next period; so that must mean we couldn't possibly get anymore benefit out of more transmission, right?

Well, this -- this case actually suggests that's wrong. We might be able with a fully loaded line to get more benefit. How? If we coordinate what gets dispatched across the two

periods, keeping in mind that one of our assets, the hydro asset, is a stock asset; and if I use it today, I can't use it tomorrow.

So there are consequences of the -- that temporal opportunity that need to be considered in the optimization of the total problem.

CHAIRMAN PICKETT: Why don't we take an opportunity and see if the Commissioners have any questions before we move in to your -- the next section. Any Commissioner questions?

Just -- I think the modeling -- I realize it's very simplistic and highly stylized and you had to kind of lock down certain parameters to be able to make sense out of it, okay --

DR. SCOTT: Uh-huh.

CHAIRMAN PICKETT: -- and there is an underlying presumption that if the benefits of economic dispatch are there, the actors will take advantage of it to some degree, given the constraints of whatever systems we're operating in.

I think there's another level that I don't have a good answer to is, all of the

utilities in the lower part of the Railbelt have made substantial investment in new generation; and in the case of all of the co-ops they would -- you know, it's either lack of generation or aging generation and this type of thing and they went to their respective ratepayers and made the argument that this new investment is critical and over time will save money, okay.

And their decisions were made in the context of their own service territory, not -- they may have given some thought to the possibility of economy energy sales; but that's so unpredictable it's kind of hard to use that as the sole determinant.

When you move into, you know, some of the cases that you went through in which there may be periods of time -- perhaps extended periods of time in which brand-new generation is left idle and -- because of economic dispatch and then you go back to your ratepayers and say, you remember all that new generation we told you was absolutely critical for some period of time that it's just not running because it's best for you?

And so I realize over time economic dispatch is a -- offers a potential for savings

for all these folks, but just how do -- how -- I don't know. I mean, I don't know how -- but after 10 years of a certain description of what needs to happen and then it's sort of -- economic dispatch has a potential to kind of turn it on its head, at least in the short run. And do you want to wade into the quagmire?

DR. SCOTT: Love to. I think partly what you are touching on is that this is not -- the system as a whole is not an automaton, right; it doesn't -- it's not a machine which operates all by itself.

It's a machine with multiple actors; that includes utility boards and utility managers and ratepayers and other utilities, some of whom you may have the perception did you wrong last time and maybe the time before that and to hell with those guys.

So people make decisions, right. And the decisions make sense at the time given what people are working with.

But it doesn't mean necessarily that sticking with the presumptions around those initial decisions generates power at least cost to consumers.

Now, if you happen to be the person -- the manager, for example, who sold a plan to your board and it turns out then that you've got generating assets that are not particularly used and useful as -- certainly as much as they might be in the near term, well, that would be uncomfortable, wouldn't it?

Because even though there might be a perfectly good explanation for what you did then and why it was a reasonable thing to do given what you were dealing with at the time, if institutions and opportunities change, it may not look like such a good decision at the time, even though it might have been perfectly fine because the problems that everybody was trying to solve were different than the problems that they face today.

Any time you have to explain something at length, there's considerable vulnerability there because, at least, I mean, your eyes are glazing over; mine are glazing over. I mean, you have to talk for a long time, people stop paying attention. It's a lot nicer if things are in bumper stickers.

And needing to go back and explain whether your initial set of answers were perfectly

reasonable at the time given the problems being faced -- and pretty soon it's like Charlie Brown, wa, wa, wa, wa, wa.

So there -- there's another thing going on, right. There are other humans, not just the managers; you've got -- or sort of at a higher level. You also have, say, plant managers, right.

If I'm a plant manager -- like, I don't know; I've never been a plant manager, but I know what it's like to own tools. And, you know, you -- you go to Home Depot and you buy a new tool; and it's like, this thing's really cool. And what do you want to do? You want to use it. At least I do.

If I'm an individual plant manager and communicating around dispatch -- and so I got a really cool tool. It's new, it works great. What do I want to do? I want to use it. Of course that's how I'm going to generate benefits for my ratepayers.

So there are lots of human motivations and reasons for doing things. And once you insert the humans into this, the overall outcome may not be necessarily an easy glide path to the least cost solution all the time.

CHAIRMAN PICKETT: I didn't mean to put you on the spot. And I liked your tool analogy. With the utilities, the tools are pretty big and they're hard to ignore.

The problem with the Home Depot analogy is if you have not disclosed it to your wife, you can't use it until you figure out a way to bring it out into the open. So with that, continue. Oh, Commissioner Rokeberg?

COMMISSIONER ROKEBERG: Good morning, Mr. Scott. I -- referring back to slide seven where you talked about the transmission costs do not rise with use, transmission tariffs inhibit economic dispatch; I'm concerned they're looking at our real-world situation now where -- were we to have a fully allocated postage stamp rate for the entire Railbelt system.

Would that not be an advantage for certain utilities vis-`-vis other utilities and, therefore, contrary to what you said? Not a barrier but a benefit.

DR. SCOTT: So there's two questions there really. The first question is: Okay, given real world, if you had a postage stamp rate when isolated just looking only at cost

responsibility for a Railbelt-wide postage stamp rate compared to where we are today, would there be winners and losers? The answer is, yes.

Because as we saw last time, some people pay more for transmission in their -- and some people pay less as a portion of their overall bill, right. That doesn't change the narrow technical point here, which is that opportunities for economic dispatch, which means using your existing asset base to provide benefits at least cost. It is the case that a postage stamp rate will generate maximal benefit.

Now, the distribution of the benefits, as you point out, matters. People will care about that. But fundamentally, if at the end of the day you can reduce the overall system cost from one state to the next, you should be able, just as a theoretical matter, right. You should be able to allocate cost responsibility in a way in which everybody's better off. Because globally the costs of the system have been reduced.

Now, figuring out how to do that is, in some instances, no mean trick, right. It will matter, and it will not be obvious. But the point is still accurate on this slide, right. And so,

again, there's a reason why on slide 10, for example, and slide 13, the last bullet is how to divide the savings, right.

That question speaks to the -- I mean, that -- the question I have on the slides here speaks to the question that you asked of me, which is, well, is it -- will people -- will people be better off? Not necessarily will everybody be better off. You get into how you distribute the benefits.

But there is an opportunity to distribute the benefits such that everybody is better off.

COMMISSIONER ROKEBERG: And to follow up on that also, when you were -- you were talking about you -- you gave an either/or here or a disjunctive postage stamp rates or fixed monthly changes. Now -- this is on seven --

DR. SCOTT: Uh-huh.

COMMISSIONER ROKEBERG: -- am I to -- am I correct in assuming that the fixed monthly charges are what, in essence, we have in the main now, excluding any economy energy sales where the -- the current ratepayers are absorbing the costs of the transmission system in their base

rates and -- and the utility is being reimbursed through their base rates for their transmission system assets?

That's where we -- that's, in a sense, where we are at today. So depending on the size of your asset base and your costs and -- and we're finding that by changing certain tariffs it has an impact on native load amounts.

So are -- when you're talking about the fixed monthly changes, are you -- is that the type of scenario you're assuming there; or is that -- am I misunderstanding that?

DR. SCOTT: No, I'm sorry, Commissioner, for not being more clear. When I was thinking about fixed monthly charge, you can imagine a circumstance in which, as part of every customer's demand charge, they picked up a portion of transmission, period.

It was just on the demand charge. It didn't show up in the usage charge at all, right. So imagine a two-part rate. You got a flat portion on your monthly bill, and that's transmission costs.

COMMISSIONER ROKEBERG: Right. That's what we're doing now, I think.

DR. SCOTT: Well, okay. I can't -- I can't speak to that one way or the other in terms of how the overall revenue requirement is divided up. I'm under the impression, and it may be completely wrong, that the demand charge doesn't pick up all fixed costs of the system.

COMMISSIONER ROKEBERG: Thank you.

CHAIRMAN PICKETT: Are there any other Commissioner questions at this point? Please continue, Antony.

DR. SCOTT: So this is just -- this is an observation. None of the modeling here assumes anything particularly about how economic dispatch is achieved. In principle, you can get there more than one way. In practice, I'm not so sure. But in principle, you can get there more than one way.

You could have one Railbelt utility that owned everything, right. A Railbelt GNT, this is, you know, the REGA and GRETC concept. That would do it, pretty sure. You can certainly imagine a series of bilateral contracts.

And historically we had quite a -- a number of bilateral contracts. Assuming sufficient flexibility, communication, knowledge,

foresight, bilateral trades in principle, there's no reason why bilateral trades cannot achieve the bliss state.

Loose pools, tight pools, ISOs, USOs; I mean, these are all various means -- the institutions are a little bit different. The demands on the information being provided and communicated across parties is different in every case.

Some people use these magic words in particular ways such that they would say, no, a loose pool cannot possibly achieve the same benefits as a tight tool because a tight pool is this and a loose pool is that. Fair enough. I mean, I don't want to argue about magic words.

But there are reasons, I think -- if -- if a loose pool means a circumstance in which we're relying on some sort of trading platform where parties -- a marketplace where parties can regularly transact, there are reasons, in practice, to be a little bit concerned because you've got multiple parties, each with their own knowledge. And they may not have the tools to adequately communicate everything that might be economic relevant to each other and have that

processed in the time to wring out all of the benefits from trade.

Whereas a concept of a tight pool or an ISO or a USO where you essentially have one dispatcher trying to achieve globally the most efficient result, in general, the information burden has been reduced because it's -- the information -- all of the relevant information is being centralized. And presumably it's contained within a central actor.

At the end of the day it's hard to say for sure whether the additional costs of having some sort of tighter centralized arrangement are worth the additional efficiency benefits that might be provided. This is something we'll talk about more later on, not today, but later on.

You have a similar issue in terms of bilateral trades. One of the issues with bilateral contracts, it's like, you and I get along, so let's think about how we could do a deal.

There's a fair amount of work that goes into trying to do a deal and distribute benefits. And once we have a contract, those

contracts will -- that -- that contractual arrangement will create rates and responsibilities on both parties, which will change the benefit cost calculus for any new opportunity that may come along.

And one of the things, for example, that we saw in the 1998 Black & Veatch work, okay, looking at possible benefits of having basically a centralized power pool tight pool of some sort is they acknowledged, oh, in CH2M Hill after, oh, you know, there are some benefits here that are available. But to get them, we'd have to undo -- we'd have to unwind a number of interlocking contracts.

I mean, this was just noted in the report. Obviously the people involved didn't work to prematurely unwind those interlacking -- interlocking agreements. It wasn't -- the benefits weren't worth the transaction costs.

So one of the things that I'm a little concerned about in terms of thinking about relying on longer term bilateral trades, which in the absence of any policy innovation, I believe are likely to occur because there are opportunities probably that are out there; but

the -- the potential downfall of that is that once you establish those contracts, then you create rigidities, which then suboptimize future opportunities. It's not as dynamic and flexible to respond to changing conditions and changing opportunities.

So even though some institutions -- but -- but, again, I want to come back -- even though some institutions on the whole have some potential shortcomings, whether those shortcomings are important enough to -- to not go down that path is something that's pretty hard to say ex ante ahead of time. All right.

CHAIRMAN PICKETT: Commissioner Rokeberg? We will take a short 10-minute break.

(Off record.)

CHAIRMAN PICKETT: We are back on the record; it's approximately 10:03 a.m. So, Antony, please continue with your presentation.

DR. SCOTT: All right. So the next portion of the morning is going to be talking about particular model runs that were done by Ken Slater, Slater Associates. And Slater is the same guy and firm who did the economic runs associated -- or that were contained in AEA's

pre-Watana study where EPS was the main contractor; Slater was the sub.

So we hired Slater to work with us to generate these model runs using PROMOD. It's a -- name of modeling platform. Slater has been working, not only with AEA, but also, importantly, with a number of other Railbelt utilities.

The advantage, of course, for -- for using Ken is that because he's been part of an ongoing dialogue, he's got much better data on how the system is operating and how people are operating the units that they have, the constraints that they have in terms of how they operate them and so on.

So more or less, some of the -- most of the parameters that are embedded in AEA's model runs and other utilities' model runs, to the extent they're using Ken, are consistent with what we're doing here. They're important variables distinguished from parameters, right. They're important variables that we're going to explore here. We're going to change variables and see what happens.

But most of the underlying parameters are the same across all of the

actors -- or all of the -- how about this: All of the clients. So that's why I want to talk about just the structure of this model a little bit, at least as I understand it, as someone who's not even remotely a practitioner of any of the relevant stuff.

So PROMOD dis -- handles generation dispatch to meet load for each hour in a given year -- for over a year -- over the course of a year within security constraints or reliability constraints. Security constraints.

So each hour's load is determined by the diurnal and seasonal load shapes in each of their service territories within the Railbelt. Those shapes then are imposed on -- or are combined with an assessment of future demand in each service territory and future -- both for power and for energy.

In the model, line losses are dynamically affected by loads. So if you have more trades between two parties and loads go up on the line, then resistance goes up; and there's line loss that's dynamically accounted for. There are various real-world constraints in terms of minimum run times for units; maximum run times,

that sort of thing; scheduled maintenance, whatever.

There are real-world stickiness or constraints that are also taken into account in terms of the need for economic gains between two parties to be big enough for it to be worth me ramping up a generator that I already have on and you ramping down. So that's like, what we call a dispatch hurdle; or bigger deal, for me being willing to turn off a unit and count on you to commit a unit for me. That commitment hurdle, that tends to be a bigger number than the dispatch hurdle.

The dispatch hurdle sort of can be thought of as a tariff, plus maybe a little bit; it's got to be worth my while; otherwise, why both? Commitment hurdles tend to be larger, bigger deal.

At some level they reflect attitudes of individual humans and collections of humans from one party towards the other. In part, in terms of trust, are you going to be good for this transaction?

There's a funny thing that everybody has done; and that is, that the dispatch and loads

are modeled in the year 2020. AEA does it; we do it. Why? As I understand it, the IMC solicit definite and collected load projection data for that year from all of the utilities. And those load data that the IMC received were then fed into a stability analysis that was done by Burlingame and his colleagues at EPS.

And that stability analysis, as I understand it, importantly, critically informs how generators can be dispatched. Because, remember, the dispatch and the units within the system needs to obey the security constraints.

So multistep process. One, tell me what your loads are going to be in 2020. Why 2020? Because that's what the IMC System Subcommittee was working with. Those loads were then used for a stability analysis, which is a separate set of modeling. That's, like, the really hard stuff, which helps create those security constraints about how you may operate the system. And then the power flow -- the economic power flows need to obey those security constraints.

The thing that's funny about this is there's a mismatch, right. Last time we talked

about costs of new transmission. There's a mismatch because big portions of that new transmission involve, more or less, a 10-year construction schedule -- not -- a 10-year development, permitting, design, and then construction schedule.

So there's a mismatch between the power -- the -- the benefits associated with economic dispatch, which -- presume that stuff has been put in place; and the costs that we've calculated for those transmission assets, which we talked about last time, which are calculated, in many cases, on the basis of them showing up and needing to be paid for in 2026.

So dropping down to the last bullet, one of the implications of that is that the realized benefits in 2026 or so of economic dispatch on an enhanced transmission system will be bigger than they are reported here, assuming that there's demand growth. Because as we'll see in general, benefits from dispatch go up the -- with demand growth.

As well, realized benefits will be bigger assuming we have inflation in -- in the differences in fuel prices in 2026 compared to

2020.

I say that because it -- although I don't do it here, one wouldn't want to compare and think you were doing apples to apples the revenue requirements for transmission. Those costs that we talked about last time, which show up, say, in 2026 in nominal dollars with the nominal dollar 2020 benefits that we're reporting here.

So the -- there's an additional step that needs to be taken before you can compare them, and even then it's pretty kludgy. It's going to be imperfect because you can't really just take those benefits and sort of trend them by inflation. Why? Because one of the important things that's likely to happen between 2020 and 2026 is some demand growth. And if we had some demand growth, then that doesn't just scale with inflation.

All right. On -- important background assumptions in the PROMOD work is that the generation additions that have been committed to or they're anticipated to come online are, indeed, online and fully operational; as well as certain transmission additions that are -- planned to be completed by 2020; some up -- upgrades

within service territories that -- that need to occur and that are expected to occur.

So we assume that that stuff is almost in and -- so it's not exactly the system as we have, but it's the system that people are planning for and have more or less committed to.

Okay. So caveats before we get into any other results. So the PROMOD modeling will not capture some of the benefits of having full economic dispatch. There is incomplete optimization of the Bradley Lake asset.

Right now, as I understand it, PROMOD basically dispatches Bradley on a -- there's a certain amount of Bradley Lake dispatch that happens on a month-by-month basis. So in January you have to use so much Bradley; and in February you use so much Bradley, and in March and so on.

Within each of those months, PROMOD will optimize. But opportunities for optimizing across months if Bradley is dispatched as a shared asset across utilities and address the full 8,000-and-something-or-other hours of the course of the year, some of those benefits are lost; they're not captured by the model. And that's

just in -- a modeling artifact; it's just how things are structured.

Power regulation requirement benefits are not fully captured, right. I mean, right now everybody needs to regulate their own power within their service territory. And that's, as I understand it, a requirement that each of the utilities adhere to.

If you had unified dispatch, the overall resources needed to regulate power would be somewhat reduced. And that just makes sense, right. I mean, it takes a certain amount of work -- a certain amount of capacity that you have available to regulate your power.

If you have five different parties each of -- doing that separately, it's going to require more work than if you have one party that's globally optimizing that. The power regulation requirements are not sort of re-optimized. So there's some benefits that aren't captured here.

And then finally, you know, some of the upgrades contemplated -- one of the upgrades contemplated is installation of the BESS. Pretty substantial BESS here. And there's no -- as I

understand it, there is no effort in any of these runs to take advantage of the reduced spinning reserves that would be -- be required to afford the same level reliability given the BESS if it was jointly dispatched -- or jointly used.

So -- so what are the main questions that we want to look at in the subsequent work? So that's all just sort of background on the modeling platform. And, again, we're -- there are benefits that we will not be able to capture and won't be shown here.

Well, one of the things that we wanted to do was to separate benefits of economic dispatch from benefits of new transmission. It is -- let's say we don't build anything new. If you had better economic dispatch, what kind of savings could you get?

Similarly, let's assume -- and this is going to be a little controversial, but, okay -- so let's assume that we built new transmission assets which would open opportunities for essentially new economic transactions between the parties; and let's assume though that the parties really don't trust each other and really have -- I'm painting an extreme and particularly

cartoonish story here about a lack of cooperation; it's not real; it would never occur in the real world, but it is the bookend -- it's the outermost edge of dysfunctional behavior -- so it's controversial because it could easily be misunderstood.

There is no indication that this is a likely outcome if you built a bunch of new transmission and you didn't have economic dispatch. But in the very worst case, what would it look like? That's why I -- we paint in -- in what follows.

Another question -- or task that we're going to review is, how do the differences -- well, one of the things that you'll see here is that our sort of base case story around benefits of economic dispatch given an enhanced transmission system and the savings that that affords compared to what's possible today, we're going to generate different savings than AEA did.

And then the question is, well, why? And the answer is, because in the main -- overwhelmingly in the main our assumptions were different. And so what we're going to do is step

through how those assumptions were different and what each of those differences resulted in in terms of cost results.

Boy, that was poorly put. And then we're -- we also want to look at, if you had new transmission with economic dispatch, that affords opportunities for -- for cost reductions. What factors particularly affect those potentially realized benefits?

And so we're going to explore sensitivities around fuel prices, a little bit on loads; we're going to look at what happens if -- because of EPA regulations, Aurora and the Aurora plant, for example, shuts down; Healy 1 shuts down. We also want to look at the importance of Golden Valley's acute reliability needs as they have -- as I have heard them articulate them.

And what I'm particularly referring to there is their articulated need to -- for the NPCC plant to run in the winter so that even if they lost both transmission lines, they would be able to meet load without substantial shed. And then lastly we'll also look at, well, what if you only did the northern upgrades and didn't do the southern upgrades?

So let's talk about our base case. Our base case is not meant to be a prediction; it's not meant to be what we think is the right answer, it's just a base case. The most important portion of this base case really is the assumption around fuel prices.

I've spent more years of my life than I care to admit trying to model fuel prices, whether it's oil prices or natural gas prices or -- and some big models. Very interesting, learned a lot, helped me think through those processes. And in terms of prediction, they were utter failures. Like radical; like useless.

But it doesn't bother me too much because nobody's any good at it. EIA's not any good at it; Exxonmobil's not any good at it. ConocoPhillips isn't any good at it.

So anyway, these are assumptions we assume in 2020 for our base case that oil rebounds to something like $80 a barrel expressed in real dollars from today's low levels. Will it? I don't know.

And we've got a pretty stout Cook Inlet gas price. And, indeed, I discovered recently after conversations with folks, it's

probably north of where I want it to be by about $0.50. The -- actually, maybe even a little more.

But the intent basically was to take the Hilcorp consent decree pricing and trend it and then also account for swing gas, and I assume in the wintertime something like 25 percent of gas is swing.

And for the electric utilities it turns out that's just the wrong way to think about it. It's way -- swing gas -- they're not purchasing swing gas, they're making use of storage. The way they make use of storage, the incremental costs of pulling gas out of storage is much smaller, the uplift, than what we've represented here.

But -- so the story is, in essence, the Cook Inlet gas price is going to be somewhat higher than, in an ideal world, I would have had it. And as we'll see, what that's going to do is serve, in general, to shrink the benefits available from economic dispatch.

Now, at the end of the day, I'm not saying it's wrong, right. I mean, who knows what Cook Inlet prices will be. In another couple years for 2020 we probably will. But remember, we're using

2020 here, more or less, as a stand-in for some sense of the size of the prize maybe.

Anyway, so this next main bullet around load forecast for GVEA. That is really incredibly poorly stated because I don't see downwards from what. I don't mean downwards from today, I mean downwards compared with what was assumed by AEA in their modeling.

AEA did not, in their modeling, have the Flint Hills refinery going away, which was a pretty substantial load; and we do. Our load for Golden Valley was -- I mean, our assumption -- and it's just an assumption -- was basically generated for us by Henry Dale, who's also been working on this project. And Henry talked with folks at Golden Valley about what their expectations are for 2020 more recently given recent developments.

And this is, roughly speaking, what we end up with. Is it right? I don't know. In any case, what we'll do is we'll see the consequence of that assumption. And so you can judge for yourself.

Prediction is not what's interesting in this process. None of this is about prediction; it's all about understanding what

moves what.

Our general level inflation was softer than what AEA assumed. AEA assumes 2.75 percent; we assume two percent. And then we explore some sensitivities.

Again, what if -- what if you have economic dispatch but no transmission upgrades or upgrades with no dispatch or, you know, what's -- one of the things we were interested in pushing, right, because there's always a big inertia from doing -- against doing anything new -- is to explore what would be needed in terms if -- Cook Inlet gas prices in Fairbanks, fuel oil prices, to make benefits from economic dispatch substantially go away.

And one of the things that we'll see as we run a case actually where, in essence, Cook Inlet gas prices and Fairbanks naphtha prices are essentially at parity. And so we'll see what happens with the benefits of economic dispatch there.

And -- and then we want to look at, well, what happens if EPA regulations make Fairbanks coal go away? Healy 1 and -- and Aurora. So separating benefits, dispatch from

transmission upgrades.

So this case we sort of have three cases here that we consider. Each of them has no transmission upgrades. In the first case where we talk about existing hurdles -- I referred before to both dispatch and commitment hurdles, which have to do with how big the size of the prize needs to be before two utilities will engage in a transaction, right.

And there's been work that Slater's been involved in to benchmark the system in 2013 to reproduce -- to try to reproduce existing generating patterns given the load. And basically they back into -- he backed into both commitment and dispatch hurdles there.

And if you use those same hurdles, which more or less reflect -- well, they partially reflect the degree of trust between the parties and the degree to which they work together. They don't fully reflect that, but they partially reflect that.

If you use those existing hurdles you get -- without any upgrades, your total all -- overall system costs over that year for -- for operation -- generation operation of about

$421 million.

If you subsequently reduce the commitment and dispatch hurdles, in other words, you increase the level of trust and cooperation; you -- you increase the level of communication with which individual humans from one utility to the next can communicate with each other, we see a savings on the order of a little over, what, $5 million.

I was a little shocked to see this as small as it was, but it is what it is. I would point out, it's on a similar scale to what Black & Veatch found in 1998.

Now, if you then, in addition, subsequently imagine a world in which Chugach, MEA, and ML&P fully pooled their loads and generating resources, if you do that without any upgrades -- and, again, this is all without upgrades -- the system's going to be less reliable than it is operated today.

But if you were to do that, you come up with an additional on the order of $14 million in savings.

And this is how it breaks out for each of the utilities in each of these cases. So

GVEA is -- you know, you can read what their costs are across the rows.

So one of the things that we see, for example, when comparing the low hurdle case where they're not part of the pool on the right-hand column is their -- their costs go up. And that's because the pooled entities are sharing benefits among themselves, right.

And so Golden Valley's going to end up having to generate a little bit more on their own; that's a little bit more expensive. And the same is going to be true for Homer. It's pretty small.

But one point that's important is when we talk about costs here, we're talking about variable production costs, which is to say, there's nothing for capital costs, right, going back to earlier this morning.

These costs do not represent any of the capital costs of generation in the system or transmission in the system or -- there are no fixed costs and no capital costs. And in addition, the fixed costs of generation are also not captured.

What we're talking about here is

only the variable costs; and it's a little bit more complicated than that because what we're talking about here when we report the -- the variable costs of a utility, we don't mean only its variable generation costs; we mean the variable costs for that utility which refers to what, fuel, the -- that they actually burn; the variability O&M that's involved in actually -- that -- that's involved in running the generating plants that's responsive to how much you run it; plus the cost of power purchased, less the cost of sales.

So power sales become an offset, right. Power purchases are an adder. If you purchase using more, presumably you're burning less fuel; and your O&M have gone down, right. So these things are offsetting each other.

But I just want to be clear, when we talk about variable production costs, they include transactions. Now, at what price are purchase and sales happening? Well, we're assuming that they're happening where the benefits from trades are being split between the parties.

Okay. So we assume split the savings. This is a particular printout of which

generators are producing less and which are generating more.

And this -- these results here on slide 26 are basically reporting what we see in the transition from the low hurdle case with overall costs of about 416 million to the low hurdles with pooling case where we have overall costs of about 402.

So one of the things that's surprising about this case is that in this particular case for this particular fact pattern, the big generator, which generates less, is Eklutna. ML&P's Plant 2 is the big winner, so to speak; it generates more. It's sub -- it's offsetting most of it, and the new South Anchorage station is also picking up a big portion of that.

There are other runs with other fact patterns given different fuel prices and different demands and different configurations where, you know, the mix of what does run and what doesn't run changes substantially.

But these are the major components of the savings in terms of what runs and what doesn't for this particular case.

I think this goes a little bit to

the Chairman's earlier question about, well -- should, for example, if this were to be realized, you know, should MEA ratepayers be concerned? And the answer is, no. From an economic perspective the answer is, no. Because as -- at the end of the day, and in the movement from the middle column here to the right column, they'd be seeing savings.

Okay. So now let's move on and talk about the transmission upgrades case. And in all of these we've got sort of low hurdles.

So let's imagine a world in which all of the transmission upgrades envisioned in the pre-Watana study have been constructed. If you -- that is -- if you consider that world with no economic dispatch and, indeed, worse than that -- much worse than that, every utility basically ignoring the opportunities provided by its neighbors beyond any economy energy that they may be transacting today.

What we see in moving from the first column to the second column is extremely modest savings. And, indeed, most of those savings are really just showing up in terms of line loss.

You've got -- if you've got much

more robust transmission system, line loss is going to be a little bit less. And that's where most of the savings are coming from.

Again, do I think this is a realistic world? Answer: No. That second column I don't think is realistic; it's way too pessimistic. However, someplace between the second column and the third column is where you would end up if you didn't have economic dispatch.

So the third column represents basically transmission upgrades and economic dispatch, and what it shows is total savings in millions of dollars in the fourth column. In total we see savings of, like, 79 million -- 79-and-a-half million.

Critically, each utility -- every single utility here is seeing savings. Some of them are generating substantially less power. Golden Valley's generating substantially less power; MEA, less power; ML&P is generating a lot more power. They're the biggest swing in this.

Overall we see a reduction in the total number of kilowatts -- kilowatt hours generated. And, again, that just has to do with the fact that in this particular run, line losses

in the system overall are reduced.

All right. So let's move on to understanding the ACEP base case against the AEA base case. Reaffirming again that this is not about predictions or best stories.

I will point out that the AEA base case assume for fuel oil in Fairbanks -- assume fuel oil prices in Fairbanks that were premised on $105 oil in 2012 inflated until 2020 at something like 2.75 percent a year. That may be an understatement. You tell me what happens in the Middle East or water regulations for fracking or whatever it is.

I mean, again, I've been so wrong on these sorts of things, like so wildly wrong, that this is as good and as reasonable a set of assumptions as any. I would -- I need to insist that we all tend to have present bias.

We all think -- because we're all Alaskans, so we all think we know something about oil prices. And all of us always think that prices in the next five years are going to kind of be -- you know, they're going to slope up from where they are now; they're going to slope down; but, you know, in five years they're more or less

going to look like what they look like now. And that's not just Alaskans, right? Everybody does that.

A year and a half ago there was nobody who was shorting oil. Nobody believed oil was going to tumble from a hundred dollars a barrel to where we see it now. There just -- there was not an analyst who was saying this publicly.

I mean, there might have been somebody out there who was really smart about -- whom a book may be written. But we all tend to assume going forward that prices are going to, more or less, look like what they do today; maybe rising a little bit, maybe fall -- whatever.

But -- so in the -- the Cook Inlet gas case, they take $6.50 in 2012 and they escalate it four -- four percent a year. It results in a lower Cook Inlet gas price than what we've got.

So what's going on? Fairbanks naphtha prices are higher; Cook Inlet gas prices are lower. You probably can predict they're going to see more substantial savings from economic dispatch with more robust transmission than what we have in the ACEP case.

As mentioned before, the load forecast used in the AEA work comes from the ICM's System Subcommittee. EMS did note in their report that those load forecasts were substantially higher than used in the Black & Veatch Railbelt IRP. That shouldn't cast aspersions on it; it's just, we've got multiple forecasts out there.

As I understand it, the IMC System Subcommittee is -- you know, what -- what they elicited was the best views at the time; and that's what was used.

So -- so let's understand differences in model benefits from AEA to ACEP. Here they are. So if you take the AEA assumptions and you update -- you run them through PROMOD with some minor tweaks and updates to reflect better understanding of what EGS is going to do, for example, of what the new Anchorage plant does and so on, you come up with an updated total savings of about $127 million.

So that's assuming, more or less, a fuel cost ratio north of the range and south of the range of about four to one. If you then take all of those AEA assumptions but then tweak only the fuel price piece, including the escalation

differences in fuel price such that the fuel cost ratio drops from about four to one to two and a half to one, the total savings available shrinks, right, substantially. $87-and-a-half-million.

And then if you further reduce the Golden Valley loads by about 20 percent -- round numbers, more or less, sorry -- the savings -- you get to the sort of last number in the -- in the right-hand quadrant there, which is, you know, where we end up in our base case of about $79-and-a-half-million of operational benefits associated with economic dispatch.

So what do we see? Importantly we see load matters, right. Golden Valley's got expensive load to serve. If they have less load, then benefits from economic dispatch are going to be smaller. But the real kicker here is in the fuel cost differences. And we'll explore that some more going forward.

So what factors particularly affect benefits? This -- again, these are sort of different what-ifs. And these are what-ifs that I've heard various folks ask or think about. What if we have a North Slope gas pipeline? Then Fairbanks will get cheaper fuel, right.

Well, we model that where basically Fairbanks fuel prices are set by the value of the gas in the pipeline; and Cook Inlet prices are set by the value of the gas in Cook -- in the -- in the pipeline; and they're separated by about $3.50, which in -- in -- means that the cost of extracting the gas in Fairbanks and handling the liquids dropout. Building a small pipeline from the main line to where the gas is needed, all costs about $3.50.

That's probably almost certainly substantially lowballing it. But it's -- it's more or less based on work that AGDC did. We'll call it 3.50.

Here's another scenario. What if Cook Inlet exploration and development is wildly successful? We're in a surplus gas world in Cook Inlet. Gas prices come down, and there's enough of it so that gas gets liquefied and trucked or put on rail to Fairbanks.

So this is a cheap world. Now, prices are separated by $5 because that's about the least expensive I can imagine -- it's less, actually, than I can imagine being able to liquefy and then move gas up to Fairbanks; but separated

by $5.

So the first is the high cost world separated by 3.50; the second is a low cost world separated by about five bucks.

Well, what happens if Fairbanks stays on naphtha but Cook Inlet runs out of gas? There just isn't enough from Hilcorp or we have to import LNG. And not only that, we've got expensive Cook Inlet gas but Fairbanks has to pay high oil costs -- fuel oil.

What if instead Cook Inlet's got to import LNG but oil prices stay low? Oil prices stay where they are now. What if Cook Inlet gas is cheap but oil prices recovered around $80 a barrel, right?

All right. Here's what happens. So if you compare the ACEP base case where you have a North Slope natural gas pipeline -- and keep in mind, obviously a North Slope pipeline wouldn't be operational by 2020; but these are sort of as if stories that we're telling throughout here -- the spread between fuel prices north and south of the range is more or less halved from two and a half down to one and a quarter.

And the savings associated with

economic dispatch are not quite cut in half. So it's a fairly close to linear relationship there.

Let's look at the trucked gas to Fairbanks case. That's, Cook Inlet is cheap and you truck it to Fairbanks and compare that with the Cook Inlet is cheap but Fairbanks pays for $80 oil, naphtha.

Well, you've got a difference in fuel price ratios of 1.75 or so to 3.1. Benefits associated with economic dispatch are actually more than double.

So, again, it's not quite linear. But we're seeing that a huge chunk of what's going on is explained by -- can be understood in terms of fuel prices -- hydrocarbon prices north and south of the range.

These last two cases look at the case where we -- Cook Inlet needs to import LNG to run our units, so it's expensive gas. We're importing it from, say, British Columbia; but we say stuck in the doldrums of $55 oil.

Now, we're looking at fuel cost ratios of about one to one. And interestingly, it's still the case that there are very material savings that show up associated with economic

dispatch. You know, $45 million a year.

How could this be? Well, clearly, for the most -- for the most part, we're not arbitraging fuel cost savings associated with gas and oil.

One of the things if you peel behind this case where it's about a one-to-one price ratio is Golden Valley starts making substantial non-winter sales of coal power south of the range. So it -- it runs the other way.

The point is, at the end of the day if you have a more robust system you open opportunities that you just don't have with a less robust system.

Interestingly here if you look at the difference in the fuel price ratios, right, in one case it's one to one; in the other case it's two to one. And it's almost -- I mean, it's very, very close to double the savings, right, from one case to the next.

So fuel price differences make -- make a big difference. But there is, apparently, a floor underneath it that is afforded by Golden Valley's coal assets and other things that you can do in terms of better dispatching Bradley Lake and

so on.

All right. So we did this set of runs with Commissioner Rokeberg particularly in mind because he's been working on this problem and has been worried -- well, "worried's" not the right word; but he's been working on the problem of EPA regulations as affecting coal-fired generation.

And so we look at a world in which the Aurora plant in Fairbanks is not able to get re-permitted and shuts down, and that same world is a world in which Healy 1 has to shut down. And we compare it to the base case.

In the first column you see the total savings with coal; it's about 79 million bucks. If coal is shut out, the savings associated with augmented transmission and economic dispatch compared with the status quo jump up about 12 million bucks. And that makes sense because there's a bunch of cheap generation that Golden Valley otherwise has that it can't avail itself of.

Commissioner Wilson?

COMMISSIONER WILSON: Did I miss where you told us what -- how you're treating

Healy 2 in these models?

DR. SCOTT: Subject to check, I'm pretty darn sure that Healy 2 is in these runs. So we're talking Aurora out and Healy 1 out, but Healy 2 is in.

So we see a benefit and sort of an unexpected benefit if EPA comes down on us of having a more robust system of on the order of $12 million a year in our base case.

Let's imagine a world in which there's cheap Cook Inlet gas and by magic somehow we can get it up to Fairbanks, not at a cost difference of $5, but at $3.50. So the cost ratio now is pretty screaming narrow.

Again, total savings go up; they go up less -- they go up less. But they go up in the no -- I'll call it the no coal case -- by about $5 million.

The cheap Cook Inlet gas case with $80 oil in Fairbanks. Again, now we've got a price ratio of around three to one. In a world without Fairbanks coal, excepting Healy 2, additional benefits are on the order of $11 million per year in 2020; imagining we had transmission infrastructure which magically

happened. So these are thought exercises, right.

Okay. And we're getting to the end, thankfully. I wanted to run a case involving Golden Valley and their reliability needs as they've articulated them.

I've heard, and maybe you have too, the assertion that, you know, you can build a bunch of new transmission between Anchorage and north of the range, and that's fine; but a lot of the benefits we don't -- we're not sure we're going to see because we're going to have to keep NPCC online. Because after all, we could lose both transmission lines. Even if you -- even if you had redundancy, that's what we do now; we keep NPCC online because we have to make sure that in the middle of winter Fairbanks doesn't go cold and dark.

And that's a perfectly reasonable way to operate. I'm not questioning that in any way.

But what I wanted to do is look at, well, that demanding reliability constraint is placing an implicit value, right, on reliability. And it's something that we've talked about as a non-billed value, right.

But what we have here is a shadow price or -- or a revelation of at least what utility management asserts they place as a value on reliability.

So you can compare needing NPCC to run in our base case with allowing it to be turned off in the winter, potentially, under our base case; and base case savings fall, right.

If NPCC runs no matter what all the time, base case savings fall by, what, on the order of $15 million. They certainly don't go away, but a big chunk of them are gone.

So what we have then is an implicit valuation of reliability against that event. The -- which event? The event in which north of the range they're relying on firm power south of the range over twinned Interties and the risk potentially that both Interties could go out.

Well, that $15 million implicit value on reliability can be put in context if -- and, again, I've relied on Henry Dale for this -- but Henry looked at records of Intertie trips between about 1990 and the middle of 2014. And in that period there were something over 140 trips -- 144, I want to say; but I'm not positive --

between Teeland-Douglas and Douglas-Healy.

So, you know, in 24 years you have 140 trips. None of those trips, according to Henry -- and I'm absolutely not qualified, okay, to opine on this -- appear to have causes that would logically or necessarily involve a trip of both lines.

I mean, the -- sort of the obvious kind of things are -- would be, like, earthquakes or raging fires in that corridor that could potentially take both lines out, right. That sort of thing.

The point is that the likelihood then of both lines being taken out at the same time appears to be, if you look at historical practice, pretty small, give or take operator error, which is a hard thing to judge, right. Whether if there's an operator error and the same operators -- hopefully the lines would be designed such that an operator error of whatever sort wouldn't cause both lines necessarily to trip, right.

But the -- the point is, this -- $15 million a year for an event which appears likely -- which historical data doesn't suggest is

likely to occur is a quite substantial value being placed on reliability.

The point is, I'm taking Golden Valley at their word that this is how they'd operate the system. That's fine.

Next time we get together I'll show you another way of looking at reliability in terms of the enhanced reliability that would be afforded by a more redundant transmission system. And it's pretty substantial.

So even if Golden Valley weren't willing to take this kind of a risk, that's fine. Nevertheless, they would be able to experience substantially increased reliability for the risks that they would take. And that's got to be worth something, which is not captured in these dispatch savings that we're talking about.

Okay. This is a -- an analog or a version to runs that AEA did in their pre-Watana study. What if we imagine that only the northern upgrades were built, none of the southern upgrades were built on the Kenai? And we look at this question across a number of different fuel price scenarios.

And what we see is that, in

general -- well, in every single case, if you were to only augment the northern Intertie infrastructures, benefits associated with economic dispatch are reduced; surprise, surprise.

The -- the thing that's a little bit interesting is that a very substantial portion are still captured. I mean, a very substantial portion is -- are still captured. I was surprised by the -- the magnitude here.

Does that mean that if you were going to today move forward and decide what to build that you would sort of take these results to the bank and say, oh, no, we're not going to worry about any of the southern upgrades? Answer: No.

I mean, all of these decisions need to be made on a case-by-case basis based on what the participants in the system demand and need for reliability; what we all, as consumers and economic actors in the Railbelt, demand for a reliable, modern infrastructure.

And in addition, almost certainly trying to model economic dispatch benefits from constructing only the northern stuff and not the stuff on the Kenai is a little goofy because the model doesn't -- we're trying to kludge into a --

results in the model that it's not really meant to do. Because the stability analysis presumes, right, that that infrastructure is in place.

So we're -- we're backing into some things. It's not way off the mark, but it's a little off the mark.

Last slide. So last week I made a big fuss about some relatively minor upgrades, not in terms of importance, but in terms of costs in the Railbelt; and it's the central Railbelt stuff, which had been reported by AEA in their pre-Watana report as having a cost/benefit ratio of over 20.

And I hypothesized, well, it could be that the benefits are grossly overstated; or here are a whole bunch of reasons maybe why those benefits aren't being captured, why the utilities haven't run out and already built that stuff already.

I need to clarify the record because I've had a conversation with the folks who were involved in that report, yesterday, actually. And it -- it turns out that the stated cost benefit savings is a drafting error, which is going to be corrected in the next go-around.

So these are not 20-to-1

cost/benefit ratio, not even remotely the case. They're very important -- from a technical perspective, as I understand it, they're very important upgrades that should be made for reliability purposes. But the economics associated with them do not reflect anything like a 20-to-1 benefit/cost ratio. So I just want to clarify that for the record.

That's something that will get picked up in the next version of that report. And, you know, these things happen; I've done it myself. I hope it won't do it for you all, but it happens. So with that I'm done.

Anymore questions?

CHAIRMAN PICKETT: Do any of the Commissioners have questions for Antony at this point? Commissioner Rokeberg?

COMMISSIONER ROKEBERG: Dr. Scott, could you just define what you mean by the northern upgrade? Does that include Lorraine and any of the DC line, though?

DR. SCOTT: Not the DC line, no.

COMMISSIONER ROKEBERG: But it does include Lorraine and the --

DR. SCOTT: Uh-huh.

COMMISSIONER ROKEBERG: Okay. So that's the roughly, what, 400- to $500 million range?

DR. SCOTT: I'm really bad at remembering numbers, but --

COMMISSIONER ROKEBERG: And you're an economist.

DR. SCOTT: I'm really bad at remembering numbers.

COMMISSIONER ROKEBERG: Okay. I just wanted to make sure I understood the scope of the --

DR. SCOTT: But we talked about it last time.

COMMISSIONER ROKEBERG: Yeah.

DR. SCOTT: Yeah. I mean, the -- those -- those bits were laid out last time, so --

COMMISSIONER ROKEBERG: And I understand here you're modeling in order to look at the impacts of economic dispatch, but I am concerned the -- of the assumptions you made regarding coal use in the Fairbanks area.

Were -- why was it decided to delete Aurora, which is not covered by EPA rules because it's below their production nameplate?

DR. SCOTT: So I don't know.

COMMISSIONER ROKEBERG: Okay. And also the -- have you discussed the --

DR. SCOTT: But -- but I would say, I think there are permitting issues with or without carbon concerns.

COMMISSIONER ROKEBERG: That could well be. I mean, there's only --

DR. SCOTT: Yeah.

COMMISSIONER ROKEBERG: -- the same would be with Healy 1 because there's a potentiality of retirement in the next 10 years, if you will, from -- based on the I docket we had under the CPP or the 111(d), so -- but I -- what I'm concerned about here is the fact -- is that what could happen and can the model be relatively easily adjusted to show the shutdown of Healy 2 also?

And then, therefore, the impacts on these various elements that -- because of the -- that would put a greater emphasis on the need for transmission upgrade and all the other ancillary areas to pick up the -- the ability to support the load to Fairbanks.

DR. SCOTT: Yes, it can be done.

It's just a question of cost. That is, every time we do a new run, we've got to pay Slater to set up the model and tweak things and make things -- it's -- it's fairly involved. It's not just like a spreadsheet where you get to change things and then it's instantly there. But the answer is, yes, absolutely that could be done.

COMMISSIONER ROKEBERG: I mean, because it's -- unfortunately it's a potential scenario that might unfold that we have to deal with; but hopefully we won't. Hopefully we'll have some success in Washington in our requests.

So I think that's all I have at the moment, Mr. Chairman.

CHAIRMAN PICKETT: Commissioner Wilson, did you have any questions? Commissioner -- okay. Antony, thank you very much. We will see you here next week at our regularly scheduled public meeting for an agenda item. So thanks again.

This will close out item number two. Number three is other business. I have no other business. Do any of the Commissioners have any business to come before the Commission? We will close out agenda item number three.

Does the attorney general have need for an executive session?

MR. GOERING: No.

CHAIRMAN PICKETT: This closes agenda item number four. Is there a motion to adjourn at 11:15 a.m. this morning?

COMMISSIONER ROKEBERG: I move to adjourn at 11:15 a.m. this morning.

CHAIRMAN PICKETT: Second?

COMMISSIONER WILSON: Second.

CHAIRMAN PICKETT: All those in favor say aye.

COMMISSIONERS: Aye.

CHAIRMAN PICKETT: Thank you for being here this morning.

(Off record - 11:15 a.m.)

I-15-001
Alaska Railbelt Electricity System

High-level modeling of
some benefits of change

5/6/2015

ACEP
Alaska Center for Energy and Power

Legislative Charge

RCA should recommend:

Whether creating an independent system operator or similar structure for electric utilities in the Railbelt area is the best option for effective and efficient electrical transmission.

Efficiency in "current"-asset context: The Stakes: FERC Form 1 report data

- Railbelt utility operating revenue = $924,000,000
  - Return *on* capital (incl. retained earnings) = 8%
  - Return *of* capital (deprec. and amortization) = 12%
- Railbelt transmission costs roughly $38,000,000
  - ~4% of total costs
- Railbelt generation O&M costs = $290,000,000
  - 31% of total costs
- Railbelt generation ***fuel costs*** = $244,000,000
  - 84% of generation O&M
  - 26% of total costs
- Reducing fuel costs is likely the biggest thing that might be accomplished with existing asset base

Outline of presentation

- 3 toy models of conditions that give rise to economic dispatch benefits
- ACEP modeled benefits of economic dispatch
  - Base case
  - Comparison with AEA's base case
  - Risk Assessment

Caveat!!!

Modeled dispatch benefits here are a small subset, and may be least important, of benefits from enhanced system (subject for next time)

What is "economic dispatch"?

- The use of *existing generating assets* to meet consumer demand at least operating cost
- "Economic dispatch" within Railbelt as a whole differs from within each service territory (space)
  - Minimizing own generation costs not enough to minimize system-wide costs
- "Economic dispatch" within a given time slice differs from over aggregate of time slices (time)

Context for "economic dispatch" cases

- Total cost = capital cost + operating cost
- Capital costs of existing generating assets are responsibility of ratepayers in service territory
  - Cost recovery not affected by whether the generator runs: "you built it, you bought it"
- Ratepayers want the minimum variable cost: indifferent to whether its bought or generated
- Because transmission costs do not rise with use, transmission *tariffs* inhibit economic dispatch
  - Postage-stamp rates or fixed monthly charges

Sketch #1: fuel cost = $10/MMBtu

- Utility A: Demand D_a = 100MWh, generators
  - $G_{a,1}$: 8,000 Btu/kWh, capacity = 90
  - $G_{a,2}$: 11,000 Btu/kWh, capacity = 50
- Utility B: Demand D_b = 130 MWh, generators
  - $G_{b,1}$: 9,000 Btu/kWh, capacity = 100
  - $G_{b,2}$: 9,000 Btu/kWh, capacity = 100
  - $G_{b,3}$: 9,000 Btu/kWh, capacity = 100

No trade case #1

- $Cost_A = Cost\ G_{a,1} + Cost\ G_{a,2} =$
  (90,000 kWh * 8,000 Btu/kWh * $10/Mmbtu) +
  (10,000 kWh * 11,000 Btu/kWh * $10/Mmbtu) =
  $720 + $110 = $830
- $Cost_B = Cost\ G_{b,1} + Cost\ G_{b,2} =$
  (100,000 kWh * 9,000 Btu/kWh * $10/MMBtu)+
  (30,000 kWh * 9,000 Btu/kWh * $10/MMBtu) =
  $900 + $270 = $1,170
- Total cost = $830 + $1,170 = $2,000

Economic Dispatch #1

- Total demand $D_a + D_b = 230$MWh
- Ramp down (off) $G_{a,2}$ and ramp up $G_{b,2}$:
  $G_{a,1}$ @ 90 MW+ $G_{b,1}$@100MW+ $G_{b,2}$ @40 MW =
  (90,000 kWh * 8,000 Btu/kWh * $10/MMBtu) +
  (100,000 kWh * 9,000 Btu/kWh * $10/MMBtu)+
  (40,000 kWh * 9,000 Btu/kWh * $10/MMBtu) =
- Total cost = $720+$900+$360 = $1,880
- Savings of 6% compared with no-trade case
- How to divide savings???

Sketch #2: Different fuel costs

- Utility A: Demand D_a = 100MWh, generators
  - $G_{a,1}$: 8,000 Btu/kWh, capacity = 90, $20/MMBtu
  - $G_{a,2}$: 11,000 Btu/kWh, capacity = 50, $10/MMBtu
- Utility B: Demand D_b = 130 MWh, generators
  - $G_{b,1}$: 9,000 Btu/kWh, capacity = 100, $10/MMBtu
  - $G_{b,2}$: 9,000 Btu/kWh, capacity = 100, $10/MMBtu
  - $G_{b,3}$: 9,000 Btu/kWh, capacity = 100, $10/MMBtu

No trade case #2

- $Cost_A = Cost\ G_{a,1} + Cost\ G_{a,2} =$
  (50,000 kWh * 8,000 Btu/kWh * $20/Mmbtu) +
  (50,000 kWh * 11,000 Btu/kWh * $10/Mmbtu) =
  $800 + $550 = $1,350
- $Cost_B = Cost\ G_{b,1} + Cost\ G_{b,2} =$
  (100,000 kWh * 9,000 Btu/kWh * $10/MMBtu)+
  (30,000 kWh * 9,000 Btu/kWh * $10/MMBtu) =
  $900 + $270 = $1,170
- Total cost = $1,350 + $1,170 = $2,520

Economic Dispatch #2

- Total demand $D_a + D_b = 230$MWh
- Ramp down (off) $G_{a,1}$ and $G_{a,2}$, ramp up $G_{b,3}$:
  $G_{b,1}$ @ 100 MW+ $G_{b,2}$@100MW+ $G_{b,3}$@30MW =
  (100,000 kWh * 9,000 Btu/kWh * $10/MMBtu) +
  (100,000 kWh * 9,000 Btu/kWh * $10/MMBtu) +
  (30,000 kWh * 9,000 Btu/kWh * $10/MMBtu) =
- Total cost = $900+$900+$270 = $2,070
- Cost savings of 18% over no-trade case
- How to divide savings???

Sketch #3: Optimizing hydro resource

- Utility A:
  - $D_{a,1}$= 80MWh, $D_{a,2}$= 120MWh
  - $G_{a,h}$: 1/2 cent/kWh, cap. = 20MW, energy = 20MWh
  - $G_{a,1}$: 8,000 Btu/kWh, capacity = 90 MW
  - $G_{a,2}$: 11,000 Btu/kWh, capacity = 50 MW; cost $10 to start
- Utility B:
  - $D_{b,1}$= 140, $D_{b,2}$= 120
  - $G_{b,h}$: 1/2 cent/kWh, cap. = 20MW, energy = 20MWh
  - $G_{b,1}$: 9,000 Btu/kWh, capacity = 100
  - $G_{b,2}$: 8,000 Btu/kWh, capacity = 40; cost $10 for to start
- Total demand: D_1=220MWh, D_2=240MWh

Intertemporal (in)efficiency: stylized

- Suppose each utility uses "rule of thumb" to take cheapest power equally across both periods
  - Period 1: 10MWh for A, 10MWh for B
  - Period 2: 10MWh for A, 10MWh for B
- Period 1 optimal dispatch:

  $G_{a,h}$@10MWh + $G_{b,h}$@10MWh + $G_{a,1}$@90MWh + $G_{b,1}$@100MWh + $G_{b,2}$@10MWh =
  \$10+\$20+\$720+\$900+\$100 +\$10 (start) = **\$1,760**
- Period 2 optimal dispatch:

  $G_{a,h}$@10MWh + $G_{b,h}$@10MWh + $G_{a,1}$@90MWh + $G_{b,1}$@100MWh + $G_{b,2}$@30MWh =
  \$10+\$20+\$720+\$900+\$300 + \$10 (start) = **\$1,960**
- Total costs = \$3,720

Intertemporal efficiency: stylized

- Suppose hydro resource is now dispatched to minimize intertemportal, overall utility costs
- Period 1 dispatch:

  $G_{a,h}$@15MWh + $G_{b,h}$@15MWh + $G_{a,1}$@90MWh + $G_{b,1}$@100MWh =
  \$15+\$30+\$720+\$900 = **\$1,665**
- Period 2 dispatch:

  $G_{a,h}$@5MWh + $G_{b,h}$@5MWh + $G_{a,1}$@90MWh + $G_{b,1}$@100MWh + $G_{b,2}$@50MWh =
  \$5+\$10+\$720+\$900+\$500 +\$10(start) = **\$2,145**
- Total costs = \$3,710

Observations

- Second case has savings of $10 compared to first
  - Uneven hydropower draw avoids plant $G_{b,2}$ startup
- Requires all actors to have complete information
  - Demand over both periods must be shared
- Hydropower value is greater than expected!
- If savings not 'large' they may be overlooked
- Analogies to transmission
  - Utility B could purchase same amount of power ("TX line fully loaded") but only one of the possible dispatches minimizes costs

Getting to Economic Dispatch

- In principle can achieve more than one way
  - One owner (e.g. REGA/GRETC concepts)
  - Bi-lateral contracts (e.g. historical MEA-CEA, HEA-CEA, Bradley Lk CEA-GVEA dispatch agreements)
  - Loose pools
  - Tight pools (1998 B&V, REGA, CH2M Hill)
  - ISO
  - USO
- Some institutions may fall short of ideal
  - Bi-lateral contracts can create rigidities that stifle future trades
  - Loose pools may fail to transmit information adequate to capture the full range of efficiencies
  - How important these deviations

PROMOD Modeling: Structure

- Generation dispatch for each hour in a 'test year' within security constraints
- Each hour's load determined by existing demand data, using diurnal and seasonal load shape
- Line loss dynamically affected by loads
- Real-world constraints (e.g. min generator runtime)
- Real-world transaction stickiness ("dispatch" and "commitment" hurdles between utilities)
  - Tariffs
  - Trust (esp. for 'firm' transactions)

PROMOD Modeling: Assumptions

- Dispatch and loads are modeled in 2020
  - Power flows based on utility demand projections
  - But: TX can all only be finished by 2026-ish
- All generation additions that are committed or anticipated are included (e.g. Plant 2A, EGS…)
- All transmission additions planned to be completed by 2020 are included
- Implication:
  - Realized benefits will be larger, when they occur, given demand growth or inflation in fuel price differences

PROMOD Modeling: Caveats

- Some areas where benefits of economic dispatch will tend to be understated:
  - Incomplete optimization of Bradley Lake
  - No capture of power regulation requirement benefits
  - No capture of benefits of a BESS on need to carry spinning reserves

Main questions we seek to address

- What are benefits of economic dispatch separate from benefits of new transmission?
- How do differences in assumptions between AEA and ACEP affect results?
- Given new transmission with economic dispatch, what factors particularly affect benefits?
  - Prices
  - Loads
  - EPA coal regulations
  - GVEA's acute reliability needs
  - What if only Northern upgrades pursued

ACEP Study assumptions

- Base case fuel prices (in 2020)
  - FBX naphtha: $25.34/MMBtu i.e. $80/Bbl oil in 2014, escalated at 2%/year
  - Cook Inlet gas: $9.75/MMBtu (continued Hilcorp-like pricing)
- Load forecast adjusts GVEA downwards to reflect current planning assumptions
  - Roughly 20% adjustment
- General inflation at 2%
- Sensitivities explored – *what put savings at risk*?
  - What if economic dispatch but no upgrades, or upgrades with no economic dispatch?
  - What's needed for Cook Inlet gas or FBX fuel to make benefits go away?
  - What if EPA regulations make FBX coal go away?

Economic Dispatch

- Separating benefits of dispatch from transmission upgrades

Economic dispatch: no TX upgrades

	"Existing" hurdles	"Low" Hurdles	"Low" Hurdles and CEA-MEA-ML&P pooling
GVEA	122.6	117.6	120.0
MEA	77.2	77.2	72.9
ML&P	77.6	76.1	74.7
CEA	99.3	100.0	88.7
HEA	44.4	45.0	45.6
Totals	421.1	415.9	401.9

- Single-year variable production costs in 2020, $millions.
- "Variable production costs" = fuel + variable O&M + purchases – sales
- Central pooled case has decreased reliability (not quantified)
- Savings on similar scale to 1998 B&V study

Economic dispatch (low to pooling): No TX upgrades

"Split the savings" assumed, but note:

Major components of Savings:

	GWh	BTU/kWh	$/MWh	$million
Reduction of Beluga Generation	14.9	48,418	582.3	8.7
Reduction of Bernice Generation	0.7	12,074	109.9	0.1
Reduction of Eklutna Generation	333.1	8,210	94.0	31.3
Reduction of Healy Coal Generation	0.4	5,088	37.6	0.0
Reduction of MLP1 Generation	1.4	1,436	27.6	0.0
Reduction of MLP2 Generation	5	20,676	205.8	1.0
Reduction in Nikiski Generation	14	7,664	76.2	1.1
Total	369.5			42.2
Increase in MLP2A Generation	266.7	7,331	76.2	20.3
Increase in Soldotna Generation	3.1	16,494	157.7	0.5
Increase in Sth. Anch. Generation	94.7	7,400	75.9	7.2
Increase in GVEA oil-fired Generation	0.7	11,697	277.2	0.2
Total	364.5			28.0

Note: There is a reduction in losses with the pooling

TX upgrades: with and w/o Ec. Disp.

	"Low" Hurdles, no TX	TX upgrades, no dispatch	TX upgrades, econ dispatch	Total Savings ($millions)	Total Generation change (GWh)
GVEA	117.6	118.8	74.6	43.0	-368.1
MEA	77.2	77.1	71.4	5.8	-137.7
ML&P	76.1	75.7	64.4	11.7	337.3
CEA	100.0	100.7	87.4	12.6	109.4
HEA	45.0	42.8	38.7	6.3	47.6
Totals	415.9	415.1	336.4	79.5	-11.6

AEA pre-Watana study assumptions

- Base Case fuel prices (in 2020):
  - FBX naphtha: $36.65/MMBtu i.e. $105/Bbl oil in 2012, escalated at 2.75%/year
  - Cook Inlet gas: $8.90/MMBtu i.e. $6.50/MMBtu in 2012, escalated at 4%/year (used for Watana studies)
- Load forecast from IMC's System Subcommittee
  - EPS notes: substantially higher than used in RIRP
- General inflation at 2.75%

Economic Dispatch

- Understanding differences in modeled benefits from AEA to ACEP

From “AEA”-2014 to RCA base cases

	"AEA updated"	AEA + ACEP Fuel & Escalation	+ Revised GVEA Loads
Fuel cost ratio	3.96:1	2.51:1	2.51:1
Total Costs "SQ"	473.4	456	416
Total Costs "TX+"	346.5	369	336
Total Savings	126.9	87.4	79.5

Economic Dispatch

- Given new transmission with economic dispatch, what factors particularly affect benefits?
  - Prices
  - Loads
  - EPA coal regulations
  - GVEA's acute reliability needs
  - What if only Northern upgrades pursued

Sensitivity of dispatch savings to fuel prices

- What if a North Slope gas pipeline comes (LNG pricing separated by $3.50)?
- What if gas is plentiful in Cook Inlet and trucked to Fairbanks (low Cook Inlet pricing separated by $5)?
- What if Cook Inlet has to import LNG but oil prices shoot back up (e.g. $110/Bbl)?
- What if Cook Inlet gas has to import LNG but oil prices stay low (e.g. $55/Bbl)?
- What if Cook Inlet gas is cheap but oil prices somewhat recover?

Sensitivity of savings to prices

	ACEP Base	North Slope PL for all	Cheap trucked gas to Fairbanks	Imported LNG, $110 oil	Imported LNG, $55 oil	Cheap CI gas, $80 oil
Fuel cost ratio	2.51:1	1.26 : 1	1.74 : 1	1.99 : 1	1.03 : 1	3.13 : 1
Total Savings	79.5	48.4	38.2	96.5	44.8	85.3

Substantial difference in savings explained by fuel price ratios

What if EPA Regulates Coal Out of AK? Explored across price scenarios

	ACEP Base	Cheap trucked gas to Fairbanks ($3.5 magic)	Cheap CI gas, $80 oil
Fuel cost ratio	2.51:1	1.52 : 1	3.13 : 1
Total Savings w/coal	79.5	33.1	85.3
Total Savings w/o coal	91.8	38.2	96.5
Difference	12.3	5.2	11.2

GVEA's Acute Reliability Needs

- Benefits here assume GVEA relies on power South of the Alaska range as fully "firm"
- Benefits decline if NPCC plant is a "must run" for GVEA in winter months to ensure reliability
- Base case savings fall from $79.5 to $64.3 million
  - Implicit, very high ($15 MM/year) value on reliability
  - ~140 Intertie trips (Teeland-Douglas, Douglas-Healy) from 1990-2014, none appear to have causes that would trip a redundant transmission system

What if only Northern Upgrades Built?

	ACEP Base	North Slope PL for all	Cheap trucked gas to Fairbanks	Imported LNG, $110 oil	Imported LNG, $55 oil	Cheap CI gas, $80 oil
Fuel cost ratio	2.51:1	1.26 : 1	1.74 : 1	1.99 : 1	1.03 : 1	3.13 : 1
Total Savings	79.5	48.4	38.2	96.5	44.8	85.3
Only Northern Intertie	68.7	36.4	29.2	77.4	35.9	76.1

Errata

- Central upgrade benefit-cost discussion from last week…?

Questions?

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STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners: Robert Pickett, Chairman
Stephen A. McAlpine
T. W. Patch
Norman Rokeberg
Janis W. Wilson

REGULATORY COMMISSION OF ALASKA
701 West Eighth Avenue, Suite 300
Anchorage, Alaska

PUBLIC MEETING

May 13, 2015
9:01 o'clock a.m.

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P R O C E E D I N G S

(On record - 9:01 a.m.)

CHAIRMAN PICKETT: Good morning. This is a public meeting of the Regulatory Commission of Alaska. It's Wednesday, May 13th, 2015, just a little bit after 9 o'clock a.m.

With me on the dais this morning are Commissioner Norman Rokeberg, Commissioner Stephen McAlpine, and Commissioner Janis Wilson. Commissioner Patch will be joining us a little bit later this morning due to some other commitments he had today.

Before I start, I am going to be deleting agenda item No. 2, discussion pertaining to economy energy sales, and that will be rescheduled for a later date.

But agenda item No. 1 is public participation. Are there any members of the Anchorage audience who would care to address the Commission this morning? Please come up to the microphone and turn it on, identify yourself for the record, and keep your comments to less than five minutes, please.

MR. McKEE: My name's Charles

post it on my web. I mentioned third party -- I mentioned Black's Law Dictionary, but not the '51 Edition -- I mean, the Fourth Edition, 1951 printing, because I didn't realize they were editing.

CHAIRMAN PICKETT: Okay. Thank you. Is there anyone else in the Anchorage audience who would care to address the Commission this morning?

Is there anyone online who would care to address the Commission?

Hearing none, we will close agenda item No. 1. As I indicated earlier, agenda item No. 2 has been removed and will be rescheduled for a future date.

Item No. 3 is I-15-001: In the Matter of the Evaluation of the Operation and Regulation of the Alaska Railbelt Electric Transmission System.

Dr. Scott, please begin your presentation.

DR. SCOTT: Thank you very much, Mr. Chairman and Commissioners. Good morning. My name is Antony Scott. I work with the Alaska Center For Energy and Power, and I'm

losing my voice.

So this is your legislative charge, is to recommend whether creating an ISO or a similar structure is the best option for effective and efficient electrical transmission. So today I want to do more or less three things. I'd like to review modeled net benefits in 2026, new transmission with economic dispatch. Two weeks ago we talked about costs. Last week we talked about benefits. This week we're going to try to put those two things together.

I'd like to discuss Railbelt reliability benefits that new institutions might promote, and also discuss evidence and benefits that coordinated Railbelt capacity additions might promote.

So, on to the net benefits. So, standard modeling caveats apply. Remember, this is with regard to AEA-sponsored study assessments of transmission costs. That study was, to a nonengineer's eyes, really pretty excellent work, but still relatively high level, plus or minus 25 percent degree cost accuracy, which means it's not exactly refined

scope. Remember that we have a mismatch in the timing of when transmission would be fully operational. It's at more or less a 10-year construction schedule to fully build out everything that was contemplated.

So by the time you'd have revenue requirements for those assets, it would be 2026 or so. Meanwhile, because of various accidents essentially, the economic dispatch modeling that was done both by AEA and by us was done assuming -- in the year 2020. So to match up cost and benefits you have to sort of "kludge" things together. They don't really synch up exactly quite right.

The reason why is last time we spent a lot of time looking at the importance, for example, of say demand in Golden Valley's service territory and how the level of Golden Valley's demand affects total benefits, for example. Well, when we're modeling 2020 power flows, in essence, when we're projecting benefits into 2026, there's no adjustment for potential load growth, which is generally what one would expect to happen over the intervening six years. So benefits associated with that

load growth aren't going to show up.

Similarly, general inflation in the spread between hydrocarbon prices also doesn't really show up, because this compounds. So, in general, the benefits in 2026 -- well, the benefits in 2020, if you simply inflate them to 2026 dollars, on balance one would expect them to typically be somewhat understated, okay, but of course it could be otherwise. So this is why I say it's kind of "kludgy."

What we're doing is we essentially take our 2020 benefits that we talked about last time, and then I just inflate them at 2 percent annual compound interest to adjust them into 2026 dollars. Why 2026? Because that's about when the transmission assets could be in place, and it's important to build in the time value of money and general cost escalation before you get that stuff online.

Of course it's always the case that economic dispatch benefits will be determined by uncertain future and hence hydrocarbon prices, demand, regulatory actions, and so on. Only some of the economic dispatch benefits are captured here. So none of the benefits

associated with power regulation, or more optimal Bradley dispatch, and that sort of thing we talked -- there was a list of that stuff that we talked about last time. So, again, in general we're getting sort of a lower -- a lower-level degree of economic dispatch benefits reported here, okay.

So having said all that, what happens? Well, this is looking at the all-in transmission build-out as contemplated in AEA's pre-Watana study as compared with the economic dispatch benefits systemwide. Here we're looking at tariff sensitivities, so we'd look at the ASEP base case inflated to 2026 benefits and compare them across different sort of policies that might be employed that would affect the cost of transmission for these new assets on a postage-stamp basis.

In general, what you see is here we've got net costs to ratepayers. This is how -- I mean, the title says "net benefits" and then this lower line here says "net costs." So it's a little awkward, but there was no clean way to do it, as you'll see in subsequent slides.

So the net cost to ratepayers in this case on an annual basis is positive; that is to say, if you were to build out all of the transmission as contemplated, and given the probably understated benefits of economic dispatch that we've modeled under our base case, what we see is that in general the benefits from economic dispatch do not fully pay for the annual costs of the transmission. However, to put that in context, the swing in ratepayer costs compared to today's total revenue requirement is pretty modest.

So we're looking at systemwide something between 3-and-a-half and a little less than 6 percent. Now, that is material. I'm not suggesting it doesn't matter; but in the overall scheme of things this is not a budget buster, I would submit, especially in light of the very substantial rate increases that are recently imminently before you from many of the utilities. So in context this is relatively modest.

Now, what you get, you get -- if you were to do this, right, if this were to happen, it's not you guys that would do any of

this, by the way, of course. I mean, I want to -- I'll stress this again, but none of the decisions around formation of a Transco and/or an ISO speak to the question of building anything. The only issues that you have to address here are whether to create or help foster or recommend new institutions that could liberate new possibilities. That's it. Whether or not building something new subsequently makes sense will be determined based on a much more complete record and much more in-depth study and consensus of the relevant parties. Okay.

So one of the things that we saw last time when we were looking at the gross benefits of economic dispatch and build-out was that the majority of the benefits had to do with the northern part of the system, constructing the enhancing transmission roughly speaking from the Anchorage area north. The central and northern part of the transmission system is contemplated by AEA.

So what I've done here is looked at, well, let's just imagine only upgrading that stuff, and we'll look at the net benefits

here. Again, we're looking here at tariff sensitivities. I'm going to look at price sensitivities in the next slide. But here the net costs to ratepayers range from positive maybe systemwide on the order of $3 million to negative maybe on the order of 8-and-a-half million dollars; in other words, on balance given base case ASEP's base case assumptions around hydrocarbon prices and more modest Golden Valley demand, essentially what you have is the promise that the transmission upgrade would be break-even with the savings associated with economic dispatch.

This is actually kind of a remarkable result. This does not normally happen. Transmission upgrades are done generally for reliability purposes. They're not done for purposes of fostering economic dispatch. All right.

So let's look at the same concept, the northern and central project costs as compared with economic dispatch benefits across different pricing scenarios. So we've got our -- and in this case I'm comparing against the right-hand side transmission costs. What

are those? I'm assuming here a private Transco, which builds these assets fairly leveraged. It's about 40 percent equity, I think is my recollection, and 60 percent debt with something like an 11 percent return on equity.

But what I assume here is that state policy -- that there's state policy innovation similar to what we saw in Hawaii to allow sort of on bill-ensured cost recovery of these assets and that can reduce the cost -- you can securitize essentially the obligations associated with the debt through ratepayer collections on bill, and that would somewhat probably reduce the cost of the debt down to, say, on the order of 3 percent in today's investment climate. That's what I'm sort of assuming here. It doesn't make a whole lot of difference one way or the other, right, in terms of the general story, but that's the transmission case that I'm assuming here. So you see the numbers are constant across the top for the costs, the annual revenue requirement for transmission.

In the second row we see the

economic dispatch benefits, which are again going to be a function of the particular story that you want to tell or scenario around hydrocarbons both north and south of the range. As with last time, you can see there's a particularly large swing in dispatch benefits, which is driven substantially by the price ratios north and south of the range.

Again, what we see here is that there can be circumstances in which the net cost to ratepayers are positive, on the order of 4 percent increase, compared to today's total revenue requirement or significantly negative; but in general the swing is really pretty modest, right. I mean, we're more or less in a world in which on a percentage basis we're coming pretty close to having economic dispatch benefits substantially cover the increased costs associated with transmission build-out. It's not a sure thing. Very little in life ever is.

Now, I think one of the things to stress, though, about this case -- again, to stress about all of these modeling results is that any time somebody wanted to build

something on a forward-going basis, hopefully you'd have a planning process and a lot of consultation among the relevant parties to make sure that it made sense; but you would have a forum in which to assess this carefully with a fully developed record.

So this is kind of a joke, but if -- so in general -- I mean, it's sort of a truism, right. You've been asked to make a recommendation around a set of institutions, and if there was a more efficient set of institutions, then it must be the case that market failures exist at some level. Market failures are outcomes in which the competitive market fails to deliver the best of all possible worlds.

What causes market failures? Well, a number of things. Economies of scale cause market failures, and this is an industry that's replete with economies of scale. We talked about that, I think, the very first time we got together. Another thing importantly is that information may not be perfect. We've talked about that in part -- we'll come to this in a moment again -- in terms of the information

being transmitted or that can't be transmitted around how people value reliability, how consumers value reliability.

Markets can fail if existing institutions entail transaction costs that are necessarily large, and market failures can also occur if there are externalities, which is to say if my transaction with the chairman creates costs or benefits that are experienced by somebody outside of that transaction.

So the existence of market failures, I think, gives you all a necessary role, a necessary policy role, and the economic regulation is justified substantially on the necessary policy role that you play to deal with the issues of economies of scale, which means that you do not have perfectly competitive markets with multiple buyers and sellers. So you have to step in in a policy way. How you do that is replete with policy decisions, but it's not a matter of simply getting out of the way and let the market do its thing, because the preconditions for competitive market outcomes producing good results are not present.

So I want to return to the issue of reliability, in part because I've just presented modeling results which seem to indicate that we could have a Railbelt transmission system, given somewhat different institutions, that provided a great deal more reliability than what we currently have. This is not a complaint about the reliability that any utility is providing. It is simply an observation that if you have redundancy in your inter-utility transmission system such that any failure of one transmission line needn't cause a loss of load, that's a substantially more robust transmission system.

We talked last time about how since 1990 there have been something on the order of 144 trips of the intertie. That's not a huge number. I don't know. Is it a big number? I can't say. It's, you know, more than four a year, five a year. I mean, it is what it is, right. Given a redundant transmission system, you wouldn't have loss of load associated with those events. Given a redundant transmission system, you open possibilities for increased levels of reliability that various industry

might be able to subsequently depend upon, and there might be economic benefits from that.

I think it's important to return to this question around the right level of reliability in the context of market failures. Consumers cannot convey their reliability expectations in a normal market way. So what that means is we have, I think, a reasonable, open question as whether customers can convey their reliability expectations to utility managements and their boards in a way that leads to the kind of outcomes that everybody hopes for.

This is a tricky problem, of course, because as long as the lights don't go out, there's no problem, right. There's no problem until there is. So if you're -- I would think -- I haven't been in this role that some of the people behind me have, but I would think if I were involved in utility management, it would be a very uncomfortable circumstance to want to pay for things that enhanced reliability because costs go up and if there's -- if you're doing a reasonable okay job in terms of providing service, customers

don't necessarily see any obvious benefit except for maybe the lights go out a little less frequently, and they probably don't know that. They probably don't easily perceive that, right.

So it's what -- reliability is about investments or about buying insurance substantially. It's like every month I don't pay my car insurance, it's like, that was a good thing. So it's not a problem until it is. So I think it's a reasonable, open question given that consumers cannot price reliability directly. I think the institutions for them to make their expectations or desires clear to management are probably less than frictionless, and it is the case that you all have statutory authority at least within service territories around this question. So at some level you are charged with assessing what sort of reliable system we should have. It's okay to delegate that responsibility to utility management, but at the end of the day that's a decision around what you're doing.

I think it's -- it remains an open question as to whether -- whether we have the

right sort of institutions to create the sort of system that we ultimately -- that ultimately serves us collectively.

So one of the things that we did in our pro mod runs is we tried to get some sense of the value of reliability that would be created by having a more robust transmission system that was robust to -- and minus 1 failures not just in generation or in transmission.

One approximation of that -- now, this is not customer value, but one approximation of that would be to look at the cost of getting to the same level of reliability afforded by redundant transmission by sticking with your existing transmission, and instead essentially having each utility carry enough spin such that if its own largest generation contingency failed, it would be able to nevertheless meet load. Because right now, as I understand it, the utilities importantly rely on each other for shared spin responsibilities or requirements; in other words, well, we can share that spin responsibility by taking advantage of the

nonredundant transmission system, right.

Well, now let's create redundancy in generation as opposed to redundancy in transmission and look at the comparative costs, right. So what this indicates is that the incremental cost systemwide in 2020-ish under our base case of each utility carrying this augmented spin requirement, which basically would mimic the same level of reliability as this enhanced transmission, would be on the order of $74 million in 2020 dollars; but note, of course, that you're now using a lot more hydrocarbons to generate the same level of reliability.

So from a conservation of resources environmental emissions perspective, conservation of Cook Inlet gas resources and so on, it may make somewhat less sense.

Now, having said that, there are important independent values, nonbuild values in terms of just doing it yourself and note, of course, that the utilities do not maintain this level of reliability, right. I mean, they depend upon -- they share spin requirements systemwide to some degree, and that reduces

their overall costs compared to what they otherwise would be in important ways. That's not a bad thing. It's just pointing out -- at all. It's just pointing out that there are reliability consequences. So you would get a bunch more reliability, in essence, for free on top of the dispatch benefits that we've previously discussed.

This is just a review of something we touched on last time. Remember that we looked at -- in conversations that I've had with folks who are formerly or currently in that utility, the assertion has been made, look, NPCCs got to be most run in the wintertime because, you know, you can talk about N minus 1 redundancy in transmission, but at the end of the day we're a long ways away and we -- if an event took out one transmission line, it could take out both and we can't afford that. We have to keep the lights on. So to do that we'll keep NPCCs running in the winter, or we would even if we had redundant transmission, and so maybe the benefits are overstated around economic dispatch.

So, again, if you'll recall last

time, we modeled the dispatch -- the reduction in dispatch benefits associated with keeping NPCC on in the winter to provide that level of security, because after all at 40 below it's no small business if you lose power. We came up with an implicit high value on the order of $15 million a year.

Now, this is probably a high estimate. Why do I say that? Well, I think it's quite possible just as the utilities take certain risks today to reduce costs to their ratepayers in terms of the level of reliability that they offer in sharing spin and so on, which I think are probably exceptionally sensible trade-offs, right, if you had N minus 1 transmission redundancy north of the range, eventually over time operators in Golden Valley's service territory would probably start taking advantage of that more and more because, you know, you need to do more with less and squeeze costs out of the system, please. It's management's job to try to drive those sorts of efficiencies, and one of the ways of doing that is to take some risks.

So it's quite likely that the NPCC

must-run concept would erode, or at least it's possible, right. So maybe these benefits are -- this reliability stated preference or revealed preference is not as big as this, but the point is -- I mean, sort of to conclude, the net benefits of an enhanced -- sorry. Net benefits of enhanced transmission infrastructure in the Railbelt if combined with institutions that allow those opportunities to be fully taken advantage of in terms of economic dispatch move overall Railbelt costs on that modest percentage points up or down, depending upon the outcome, and in addition provide material reliability improvements.

What those improvements are worth is a little bit of an angels on top of the head -- you know, dancing on a pin question. It's not easy to say. Consumers can't show what those reliability (indiscernible) are worth. We have some ability to gain indications from modeling around what the cost of providing that enhanced reliability would be on the one hand. If you were to do it without transmission, it's pretty substantial, right. Without transmission it would cost you another

75 million bucks a year anyway. We also have some statements from utility managers indicating that reliability is awfully darn important to them, and they're willing to pay a substantial amount of money to get it. Okay.

So let's now turn to transmission builds, market failures.

If we could, I'd like to take a short break.

CHAIRMAN PICKETT: This would be a good time for a short ten-minute break. I will note that out front are a summarization of the responses to the orders we've had on the regulatory authority and the reply comments. So I'd suggest if you'd like to pick a copy of them up, and if the characterization of your comments is not what you think it is, let us know.

So we'll be back on the record at about five minutes to 10:00.

(Break taken.)

CHAIRMAN PICKETT: We are back on the record. It is approximately 9:56 a.m.

Please continue, Dr. Scott, with -- I believe we're at the free-rider problem.

DR. SCOTT: Thank you very much, Mr. Chairman.

So we've got a market failure, right, around reliability. There's no good way for information about its value to be transferred to the people who might otherwise provide it. We've also seen that increased levels of transmission confer substantial reliability benefits to the point where if you wanted to provide that same degree of reliability benefit, for example, merely through enhanced generation, there would be substantial costs, right, with no ability to conserve resources.

So on top of that, though, we have a free-rider market failure. If reliability can be provided by transmission, we have this unfortunate problem where inter-utility transmission assets can provide benefits to parties that don't necessarily pay for their full cost. So if you enhance -- let's say you have -- well, I won't come up with toy models on the fly, but this is a regularly recognized problem in FERC Order 1000, a relatively recent FERC order, this dynamic -- the problem of

getting transmission built to provide needed reliability within regional transmission systems is -- I mean, it's not an easy problem to solve, and FERC alludes to it repeatedly throughout the order.

Here's just a quote from -- I mean, one isolated quote from one part of the order, but what they say here is that where you have transmission investment that affects multiple utilities' transmission systems, which is the kinds of investments that in general we've been describing here, which therefore might have multiple beneficiaries, any individual beneficiary has got a substantial incentive to defer making a decision about taking the lead on that investment and hope that other people will do so instead. That's especially the case historically, I think, in terms of the dynamics in Alaska where we've had substantial state investment and involvement in various infrastructure projects.

None of this -- the issue of free ridership is not -- to point to it is not to suggest that anybody isn't doing the very best by their own ratepayers that they can. In

fact, the free-rider problem happens precisely because management is doing the best that they can for their own ratepayers. The problem is when benefits can be enjoyed and you don't necessarily have to pull -- pay for their full freight, it creates perverse incentives such that you don't get the full degree of benefits provision that would otherwise be efficient or effective.

So FERC Order 1000 and prior orders that the FERC had made are directed towards creating a regulatory framework to help try to solve some of the free-rider problems through planning. In this case, right, reliability has benefits, transmission provides reliability, building transmission has got free-rider problems. Right now we don't have a good business case in the Railbelt for building new transmission, because we don't have centralized planning around what new transmission assets should be built.

Substantially we're leaving that up to individual utilities to do or to pull off bilateral agreements or multilateral agreements. That's not to suggest that that

can't happen, but as a general matter one should expect -- it's kind of a theorem that in economics that if there are free-rider opportunities, in general you're going to have underinvestment in those sorts of goods.

So right now, right, historically what you -- you haven't had separate transmission tariffs. You all have a number of rate cases in front of you where you've had to wrestle with that problem as you're moving into a new system, but historically transmission was bundled in on a wholesale basis with the electricity that was sold. It was a bundled service.

So you can try to recover the costs of transmission from somebody else who is a beneficiary through some sort of open access tariff provision. The problem is the risk. If the transmission is in your service territory, wholly or substantially, you bear a risk for -- your native load customers bear the risk of nonrecovery, even if you fully expect, oh, I think it's likely that those other guys are going to be using this a lot and, oh, I think it's likely that they'll receive benefit, or I

think it's likely that the Commission will see eye to eye the way I think they should see it and structure tariffs accordingly; nevertheless the risk of any of those things not taking place falls upon the native load customers, because at the end of the day, if cost recovery isn't shared adequately, with air quotes, with the neighboring utility or the other utilities that use those goods and services, then you have customers that have to eat it.

What does that lead to? It leads to if you have any -- if you have management that is all risk averse, it leads to underinvestment in transmission. The other thing that it leads to is let's say those risks are undertaken indeed. What it leads to is transmission rate pancaking where everybody is trying to recovery transmission costs from other utilities through open access tariffs and we have multiple transmission tariffs. One of the things that we saw last time is that the imposition of transmission tariffs between utilities prevents or distorts economic dispatch among those utilities, and that's substantially goofy. It's not an ideal outcome

because, again, the transmission costs are really substantially fixed and who benefits how much will evolve actually over time. So it's an evolution which leads, I think, to fragmentation.

Again, that's not necessarily the wrong answer. I mean, there are -- there are visions of the future where it's a distributed generation world and increasingly the overall utility business model breaks down, and substantially we are all -- substantially we're providing for our own needs on a much more localized basis. I mean, that's sort of the end point. Maybe that's fine and in 50 years maybe that's what everything will look like. It's possible.

But from a high level, looking at this from the outside, I'm very flatfooted about these things, and I'm kind of skeptical about that view of the world. That's just a comment about me and nothing else. So I'll make a prediction, that if we do not figure out a way to create a new business model for investment in transmission, we will have a reduction in reliability in the Railbelt, which

can only be compensated for through increased generation responsibility by each of the separate utilities.

The poster child of this, I think, is maybe Chugach's submarine cables, which are pushing 40 years old. They're a very important transmission path. As I understand it -- I'm really speaking outside of my field now. So if there's people behind me who want to hit me about the head, you know, I'm totally undefended and you should go ahead and do it. But as I understand it, these submarine cables are really a very important transmission path for energy from Anchorage/Kenai up north, and their failure would affect reliability for MEA and GVEA at minimum.

So those are Chugach's submarine cables. If they failed, as I understand it, and this, you know, may well be an undisputable point, but Chugach would be able to meet its own needs and loads substantially. I mean, as I understand it, those cables were in part constructed around wholesale power contracts that no longer are particularly important -- well, they don't exist anymore. It's entirely

possible that the relevant parties could come together and solve a cable failure or solve the need for forward-looking cable replacement on a proactive, going-forward basis in a bilateral multilateral way. It's entirely possible. It happens. Just because there are free-rider problems, it doesn't mean that transmission investments do not occur. The assertion is that they occur less frequently than would maximally benefit all parties. But there --

It would require some proactive problem solving. It would require some significant undertaking of transaction costs when everybody's got an awful lot of other things to do right now always. It would also require not hoping or lobbying the Legislature to solve the problem. The promise that the Legislature might step in to solve the problem through investment, if I were in that management position, that would be an almost impossible -- I mean, it would be a siren song that would be almost impossible to not be seduced by.

The promise of that, of that as a business model, I think, by itself creates an

important dynamic around delay. Of course once a cable like that goes out, you've got issues, and it will be multiple seasons before you can get things handled.

So I'm about to go into something that is probably quite contentious and I --

CHAIRMAN PICKETT: Would this be a good point for Commissioner questions?

DR. SCOTT: Absolutely. Any time. You should just interrupt.

CHAIRMAN PICKETT: Do any of the Commissioners have questions on Dr. Scott's presentation so far?

Looks like Commissioner Rokeberg is reaching for his mike.

COMMISSIONER ROKEBERG: Good morning, sir. We're both suffering from allergies.

One thing I'd like to go back to is your comments regarding the incremental cost savings from the consolidated spin. You indicated there was potentially, as I recall, in 2020 or 2026 a potentiality for $74 million in savings. Would that not be obtainable by a consolidation and joint planning for that

vis-a-vis new transmission asset construction?

DR. SCOTT: Commissioner Rokeberg, let me apologize for not being clearer.

COMMISSIONER ROKEBERG: Okay.

DR. SCOTT: This is a little modeling exercise. In essence what I'm suggesting here is that the utilities are saving today material dollars, tens of millions of dollars they are saving right now through how they collectively manage spin obligations on the Railbelt; however, how they do that has reliability consequences. I'm not suggesting for an instant that those trade-offs are not optimal or appropriate.

What I'm trying to indicate in this slide here is that part of what is left out in this sort of net benefit calculation is a substantial increase in reliability on the system as a whole. Jumping ahead to this slide, to slide 10, what slide 10 is meant to represent is if you wanted to get the same level of reliability that you get under, say, slide 5, not through transmission but instead through generation, you would have to change the rules or procedures or practices around how

spin gets carried individually and collectively, and to do that would entail an increasing cost of about $74 million.

So if you were to -- I'll try to say this another way. Absent increased transmission investment, to get the same level of reliability that is afforded by that increased transmission investment, one would need to change the procedures and practices for how spin is carried, which would increase costs on the order of $74 million a year.

COMMISSIONER ROKEBERG: Okay. I think I was suffering from my own malady in my vision right now by misinterpreting costs for benefit. So -- yeah, I'm glad I asked the question so I can be clear in my own mind.

DR. SCOTT: I'm glad you did too, and I apologize for not --

COMMISSIONER ROKEBERG: No, no, no.

DR. SCOTT: -- scaling this out more clearly.

COMMISSIONER ROKEBERG: I may have not heard you either. Forgive us both. I appreciate the -- the consolidation may prove beneficial too, or different practices.

Also, to clarify this point, to stick with it, then, to make sure I understand it: Is there an indication that new transmission asset investment would be necessary to be able to implement a greater amount of benefits on the shared spinning incremental loan? Would that be correct then?

DR. SCOTT: I think it is correct to say that if you had enhanced transmission capacity in the system as a whole, then the opportunities systemwide for reducing the amount of spin that needs to be carried within security constraints would be reduced, because you'd have a greater degree of security provided by the transmission instead of needing to carry that same security through generation through spin.

So that reduction in spin responsibility and cost, however, is -- the actual generation part of that cost is indeed captured in these sorts of results here on slides 5, 6, and 7. So slides 5, 6, and 7, which provide for economic dispatch also include -- I mean, part of the benefits of economic dispatch involve some change in how

spin gets carried on the system. I say some because -- well, it gets into technical issues around how we're modeling the system as a whole from the stability analysis that was initially done and upon which the pro mod runs are based. We are -- there's an apples and oranges problem a little bit. We're probably understating some of the opportunities that exist in terms of reduced spin. But, again, slides 5, 6, and 7, these numbers on net benefits have baked in some of the benefits of reduced spin needs.

COMMISSIONER ROKEBERG: Thank you.

On another area that's kind of wide open regarding the free-rider problems and Order 1000. Is it -- has not the FERC taken positions that indicate in the major RTOs in the Lower 48 that if there's benefits accrued to the whole system, that they have a tendency to favor implementation into their base postage-stamp rates throughout the entire RTO? As a rule they tend to favor that --

DR. SCOTT: That's my understanding.

COMMISSIONER ROKEBERG: -- because the implicit benefit may expand beyond the

empirically verifiable amounts and also -- however, though, it's also my understanding among other RTOs that they do particularly for project financing and implementation of new asset transmission development particularly, that they would price them zonally with different tariffs to reflect the immediate beneficiaries with a higher responsibility -- greater responsibility for those costs.

How would that relate to such a small area? We're only -- for 600 miles long we think it's large, but if we put a new SVC in Healy, it may well have an effect that the whole system -- as well as one at, for example, the Soldotna Substation.

DR. SCOTT: So you're asking really good questions, I think, about rate design and what makes most sense and cost recovery and responsibility.

CHAIRMAN PICKETT: And I'm going to --

COMMISSIONER ROKEBERG: Can you give me an example of free ridership in the Railbelt, though? Maybe that will help.

CHAIRMAN PICKETT: I am going to

use the power of the chair. I'm sure all the parties in the room are anxiously awaiting the Homer order, and we will leave it at that.

Commissioner Wilson, did you have any questions at this point?

COMMISSIONER WILSON: Yes. If you go back to slide 9, N minus 1 transmission -- oh, my slide 9 is different than yours.

DR. SCOTT: Yeah, I'm sorry about that.

COMMISSIONER WILSON: It's the one on N minus 1 transmission.

DR. SCOTT: That one.

COMMISSIONER WILSON: That's the one.

DR. SCOTT: Yeah.

COMMISSIONER WILSON: How are you defining N minus 1 transmission?

Is that basically 100 percent redundancy in the lines?

DR. SCOTT: Basically if you're depending upon a line for transmission, if that line fails and you can maintain security, the system as a whole, even given a single line failure, that's all I mean by N minus 1. So,

for example, the -- well, I'll just stop there.

So right now we're at a point where if we have a single point of failure, we can lose load unless we're carrying enough native load generation -- I mean, enough generation within a service territory to survive that. So we're making up with -- to provide the same level of security, we have to have more generation within each service territory.

COMMISSIONER WILSON: And that's assuming adequate transmission within each service area. And that was my next question: The 74 million is based upon everybody -- is based on individual service areas of individual utilities; is that correct?

DR. SCOTT: That is correct.

COMMISSIONER WILSON: Okay. So each utility would be carrying its own spin?

DR. SCOTT: That is right.

COMMISSIONER WILSON: In accordance with what's required by the current reliability standards that have been agreed to by some of the utilities?

DR. SCOTT: Right, but again the idea is right now some of the -- the rules

around spin, as I understand it, allow some effective sharing, right.

COMMISSIONER WILSON: Uh-huh, yes.

DR. SCOTT: If each utility needed to provide spin for itself such that they could handle loss of its largest generation contingency, then this is the result in terms of the increase in costs.

COMMISSIONER WILSON: And is that increase primarily in gas costs or other variable costs?

DR. SCOTT: Fuel and other variable costs, yeah. That's all we're modeling here.

COMMISSIONER WILSON: Okay. Thank you.

DR. SCOTT: Uh-huh.

CHAIRMAN PICKETT: Before Antony begins with lobbing whatever grenades he has in the remainder of his presentation, I want to go back to, I think it's slide 14, on the prediction of reliability decline. This is something I've sort of thought about for a number of years in just the role of the submarine cables in the system, and has that actually changed with all of the new generation

and as you have indicated, some of these assets are rather old.

Submarine cables are very expensive, and they're expensive both on the CAP-EX side and on the operational side and probably are last -- we've had some of these types of discussions in the context of rate cases, but not so much on cost elements. It's more, you know, on the VAR issues and that type of thing, but with Fire Island wind PPA, for example, we became very aware of, you know, a $25 million rather small submarine cable and just the challenges with that. That was basically free money from the Legislature, and it still took a while for all those pieces to come together.

Now, if you had the failure of a submarine cable in the inlet -- and that's one of the things that I think is sort of leaning me more favorably towards the creation of some sort of an ISO type of structure, is I'm just not convinced that the financing and funding mechanism is there for those types of transmission assets that sort of transcend the boundaries of one particular utility. I would

actually welcome utilities in the room, if you've got some ideas on this slide 14 and how it does impact reliability, you know, given the new generation, to submit them into this docket.

But any further observations on that? I just don't see -- like, if you had a $100 million transmission project that failed catastrophically suddenly, I don't think it's realistic to expect you're going to go to the Legislature and get some kind of timely action on that. That's going to be a very tough issue, and I think it's going to be very tough when you just look even, say, at the example of the Eklutna Operating Committee and that line and just the challenges with getting all the pieces together to energize a line; not to mention the lead times with ordering the submarine cables and all that stuff.

So any additional thoughts on that, or you'll just let the slide speak for itself?

DR. SCOTT: I think one of the things that was instructive for me in going through AEA's pre-Watana study and digging into the appendices a little bit and looking at the

schedules around new transmission -- I mean, one of the morals of the stories there is it takes a while. You have to do permitting and you have to do design and you have to do that before you get to do construction. You know, anything dealing with Cook Inlet -- I'm really speaking out of school -- but I would imagine there's a possibility at least of having to worry about beluga whales and NMFS and, I mean, what a mess.

So, in general, the point is these are longer lead time projects. It's not necessarily about going out and fixing stuff in a hurry. Okay, let's get to it. So in general you want proactive problem solving. You solve the problems before they occur rather than after.

I have concerns that without an overarching structure it's not anybody -- any one individual entity's responsibility to make sure the problem gets solved. As all of us have worked in large organizations, we all know if the responsibility for doing a job that doesn't provide disproportionate rewards to oneself doesn't fall to anybody, those things

often don't become the primary goal of any one party, and in that kind of a world things fall through the cracks.

So fundamentally it's a story, I think -- I mean, I think we just need to recognize that this is a real possibility. It's not to suggest, again, that it can't be solved. It can. Bilaterally, multilaterally it could. The next portion of what I'm about to present is arguably a history lesson indicating that just because things could happen, nevertheless they don't always and the consequences can be costly.

CHAIRMAN PICKETT: So, continue.

DR. SCOTT: So let's look at past studies. Before I launch into this, I want to stress something. None of this is a criticism of any individual utility at all.

I believe the following: As I've said numerous times, you have multiple companies with managements and boards that are striving to do the very best they can given the institutions and incentives that are in front of them. One of the overriding themes of my presentation is to you is that the institutions

that -- sorry. There are reasons which get in the way of perfectly efficient economically efficient outcomes where the equilibrium best results of parties acting disparately may not be as favorable as when they act in concert, and yet if the cost of any one individual trying to act in concert with a bunch of other folks doesn't yield proportionate rewards and if you don't have the institutional glue sort of binding folks together to do stuff, it may not happen. That's, again, not a failure or a condemnation of anybody. It's a recognition that we all operate within incentive structures. All right.

So having said that, in the 2007/2008 time frame there was public recognition of a couple things. One, MEA and Homer had made clear that they were not going to continue being requirement wholesale customers of Chugach Electric. In other words, a portion -- a substantial portion of the pooling that had occurred previously, that bilateral and multilateral set of structures was going to be going away.

There was also increasingly concern

that, hey, gas from Cook Inlet which had always been -- reserves to production ratio had always been ridiculously high, that was beginning to tighten up and approach reserves to production ratios that you normally see in the Lower 48, much more sort of reasonable reserves to production ratios, but it led to a great deal of concern that we were running out of gas and that there wasn't going to be any more discovery and production of reserves in Cook Inlet, and we were potentially looking at a real pickle.

There are market failures there which I've spent an awful lot of time thinking about, but we won't talk about the Cook Inlet gas issues right now. But what -- these facts raise a couple of questions: How are we going to plan for new generation? Because if Homer and MEA weren't going to be requirement customers, they were going to need to provide their own generation or figure something else out -- and what to plan for new generation.

I mean, if gas from Cook Inlet looks like it's getting scarce and expensive, what should we do? Well, here's what did

happen. A bunch of decisions got made about what to commit to going forward, and this is what folks committed to roughly speaking in terms of when things would come online in their installed capacity. Unfortunately, that slide is out of order. I wanted that later, but out of the context of slide 15 we got the REGA study.

So AEA sponsors Black & Veatch to do the Railbelt Electrical Grid Authority study. What that study did, it did a lot of things. It's a pretty interesting piece of work. Technically one of the things that it did is it forecast future demand based on the input from the utilities. Then it did a bunch of economic modeling asking: What capacity additions can most cost effectively meet that forecast demand for different resource mixes?

So there were multiple scenarios run, sort of continued reliance on gas, other things. So one of the things that the study found was that there were material savings that could be afforded by central coordination of generation and transmission construction, and of course they recommended the formation of a

generation and transmission cooperative. But the finding around material savings from coordination of planning and construction echoed similar findings from a decade earlier in which Black & Veatch also engaging in a similar modeling exercise found, you know, if we have joint construction planning, you can in fact defer substantially some new construction needs. This is not a novel or new result. I mean, this is commonplace.

If everybody is meeting their own needs given the need for reliability, if everybody is acting individually, you will overbuild compared to if people are acting in concert, which is to say you can defer investment if people are acting in concert than if you're acting individually. Why? Because there are constraints imposed in this business for needing to provide reliable service.

So you need a lot of generation capacity to be able to ensure that you can do that. All right. So -- sorry, this slide 16 really should follow this slide. This is what got built, okay.

Slide 18 shows -- I need to pause

right now and recognize Chris Pike, who's a colleague of mine, is sitting behind me. I think he's not one of the people who are muttering complaining about what I'm doing. But Chris is the person who's pulled the data from these reports as well as pulled data from annual reports and other materials submitted to the Commission. But the -- this is groovy.

These paths here, okay, are different resource mix paths and generation addition paths that were modeled by Black & Veatch as being required or sufficient to meet projected demand growth. So on the Y axis here we have installed megawatt additions, okay. So this is indicating: What do you need to add in terms of installed capacity additions to meet the projected load growth going forward over a very long time horizon?

And these lines here represent future time paths of generation that you need, and each one is tied to a particular resource mix. So different resources mixes require different going-forward needs. So here's what was built and committed to. There we go.

What we see is a big acceleration

in construction of generation assets. Why on earth would we see a substantial increase acceleration construction of generation assets compared to what Black & Veatch indicated might be optimal to meet demand? Well, there is an answer. That is, Black & Veatch was assuming in these charts here, right, in these growth generation construction scenarios, they were assuming that the utilities were jointly planning generation additions to meet their joint needs.

So the slide is meant to suggest -- to indicate we have arguably a history lesson that if you have joint planning, indeed you can defer a bunch of new generation additions. So if this is right, what this suggests is that although there are material benefits that might have been achieved had there been a structure to create incentives for the utilities to pool their efforts and there was not such a structure, but had there been, significant generation additions might have been deferred.

This goes back to the chairman's question about transmission additions. It's the same dynamic. While it's entirely possible

that these sorts of results here could have been achieved through bilateral or multilateral cooperation, absent institutional structures that pushed parties together to achieve those outcomes, instead you can indeed end up in a world in which everybody is acting optimally, sensibly for their own needs, but it produces a less globally optimal outcome.

So in 2010 there was a follow-on study again performed by Black & Veatch looking at doing our regional Railbelt integrated resource plan. That plan -- the modeling exercise there followed essentially a very similar approach as the REGA study. It forecasted future demand. It determined capacity additions that most cost effectively meet forecast demand for different resource mixes. It did assume a significant degree of dispatch, economic dispatch. It built in the capacity commitments -- generation capacity commitments that had been made at that time.

So the REGA study was in 2008 and this was what was forecast, right. These capacity commitments have not yet transpired. Again, I apologize for having these slides out

of order. By 2010 those capacity commitments had been made. Those got built into the forecasted need, and what we see here are -- red indicates load with a 30 percent reserve margin. Green indicates the existing and committed capacity and generation on the system. You see this new great big hump in generation capacity well in excess of what would be needed to meet projected load.

The blue is load adjusted if you had quite aggressive demand side management efforts. So there's the hump. That's what transpired. It's what was baked into the study. What it suggests is that basically no new -- that the committed additions when coupled with gradual retirements on the system would be sufficient to meet load with a 30 percent margin up until 2030.

What that's saying at least as -- when I look at this what I take from it is that we have substantially preinvested in generation assets beyond what is needed until roughly the 2030 time frame. Now, new generation assets would have been needed. Not suggesting that you could have waited until 2030 to do

anything. That's not the case. What I'm trying to say, though, is -- I mean, in an ideal world, right, you would add only so much as you actually needed to meet load then. That big hump in committed additions that you see there in green and circled indicates, I think, that all of the parties acting sensibly, optimally, given the incentives in front of them at the time nevertheless produced a result in which there was significant overinvestment.

Where that overinvestment needs to be understood compared with a different set of institutions, that is to say if you had had a different set of institutions, you could have deferred substantial investment.

So when Chris was putting this together and we were talking about it, one of the obvious potential problems with this analysis is well, look, maybe Black & Veatch got the demand forecast wrong. Maybe there wasn't really overinvestment globally compared to what was needed to meet led. You really did need all of this generation added no matter what. That's really the question. Did you need to add all of it no matter what, right?

And the answer might well be the case, yeah, because see that red forecast? That's way wrong, right. So we wanted to look at that. So the blue lines represent -- and I apologize for this because I didn't -- this is a software screw-up on my part. I didn't paste this that you could see utility by utility each of the forecast loads, but this is showing forecast loads using modeling work. The blue is the REGA study on a utility by utility basis. The red is the Railbelt IRP study, so separated by a couple of years.

In general what you see is that the forecasts differ a little bit going forward over a very lengthy multi-decade period of time. They vary somewhat utility by utility, but when you mentally sort of put them together, they're pretty darn close one to the other.

The other thing, though, that's interesting is that the green shows actual peak loads on a utility by utility basis. So this is indicating the actual data on peak loads that Chris was able to pull from various reports. What we see is that in general

there's very little evidence to suggest that utility peak loads were outside of what was forecasted in these studies.

Now, it's possible that, you know, a decade out the studies got these things really wrong, but the data don't seem to suggest that. You know, granted, there's not a lot of the green to compare to these multi-decade forecasts, but, again, remember the demand forecasts were substantially informed by Black & Veatch conversations with utilities. I mean, this work doesn't work without utility input.

CHAIRMAN PICKETT: I think this would be a good point for a ten-minute break and then we can come back, wind up the presentation and Commissioner questions. So we will try to reconvene just a little after 11:00.

(Break taken.)

CHAIRMAN PICKETT: We are back on the record. It is 11:04 a.m.

Dr. Scott, please continue.

DR. SCOTT: Thank you very much, Mr. Chairman.

I alluded earlier to the loss of labels on slide 21 in the upper half. I'm sorry about that. It's a function of trying to put this together and not having my reading spectacles at the time on the airplane last night.

In the upper left -- people have been asking about the labels. In the upper left is Chugach Electric. It's the northwest quadrant. In the middle is Homer, and on the right is MEA.

So this is a really terrible thing. It's unfortunate because to use -- sort of cherrypick testimony that people provide, but last fall some of you may have attended a legislative round table that Representative Isaacson sponsored over in LIO here in Anchorage. Harvey Ambrose from HEA provided testimony. It was very illustrative and helpful.

He said -- in talking about Homer's efforts, he said: Before we built the unit at Soldotna, Chugach suggested, unfortunately too late, that we put that unit at Beluga. Homer would own it, but it would be physically

located in Beluga, so it's not competing with tie line space coming up here. It would have been used more, and we would have gotten greater value out of it. Unfortunately we were too far down that road of building it at Soldotna to reverse course, but it was a good idea.

What does this say? It says that communication costs something. Transactions working together cost something. If parties do not have a structure to force them to work together and to adequately share information and to create vehicles and institutions and mechanisms by which the information is shared, it may not happen in a timely fashion. This is an example, a particularly clear example in which we have somebody in a utility explaining that there was a failure in information transmission, which had it not occurred, would have created value for everybody.

So this is just another particularly clear example that although it's the case that bilateral and multilateral transactions absolutely can result in efficient outcomes, it is also no guarantee that just

because there are benefits to be had that they will indeed occur.

CHAIRMAN PICKETT: Commissioner Rokeberg, you have the mike.

COMMISSIONER ROKEBERG: With all due respect, Mr. Ambrose -- perhaps in his defense, I'm not sure -- and I was there. I'm not sure the context is correct, but wouldn't this presuppose the implementation of the EPS plan for the construction of the under-inlet DC conduit, or then the site location out of their even service area to build a generation plant?

DR. SCOTT: No, I don't think it does presuppose the construction of that cable. I think what this is referring to is just the physical location outside of their service territory of a generation asset. It would have been co-located in the Chugach service territory, but it would have provided more overall benefits for Homer ratepayers at the end of the day.

So market failures happen in this business a lot. That's not a bad thing; it's just inherent. It's just an observation. So in terms of -- I want to talk about now how to

think about getting to economic dispatch. This is a little bit of a preview of stuff we'll talk about more next time.

But in principle you can achieve economic dispatch more than one way. You can have one owner and that was, for example, what the REGA study recommended. Out of that came the GRETSI concepts. Have one G&T. If you have one G&T, then all of the necessary information and coordination can be readily handled because you've got one actor rather than trying to coordinate across multiple actors with multiple constraints.

So that was a recommendation at the time. It's not a new concept. I was recently reading an order from this Commission in 1985, which was concerned with whether the Commission should force the creation of a G&T to serve Homer and MEA and Chugach's collective needs. I think this is not a viable or a realistic path. I mean, in principle it certainly could happen, but transaction costs around pooling generation assets like this in terms of ownership are difficult to say the least.

Even given the prospects of very

significant infusions of State dollars at the time, there was no ability for the utilities to sort of come to a meeting of the minds among themselves to present a package to the Legislature that everybody could feel good about. Given that we're not rolling in dough anymore, I think the idea of being able to get there through the provision of carrots is very unlikely. Absent that grease, I'm not sure that this is in the offing. I personally just don't see a way forward. I believe Commissioner Rokeberg feels the same way.

CHAIRMAN PICKETT: Commissioner Rokeberg grabs the microphone.

COMMISSIONER ROKEBERG: Just for the record, the No. 3 recommendation of REGA was for a Transco-like transmission authority not a G&T, at my insistence.

CHAIRMAN PICKETT: Continue.

DR. SCOTT: So another sort of bundle of ways of getting there is through -- we can call it centralized planning of some sort, right. You can have a tight -- what's variously called a tight pool or some people are calling a unified system operator or you

could have an ISO. For my purposes, right, I've said before I kind of hate the magic words that get thrown around in this industry.

So only for right now, for my purposes, I want to distinguish between these two concepts in the following way: From my perspective -- ISO, the I stands for independent system operator. ISOs were created out of the need in the Lower 48 for the generation decisions to be made fully independent of the transmission assets in order to facilitate competitive provision of wholesale power. ISOs are about making markets -- wholesale markets function. I really believe that that concept should be sort of reserved for that context.

ISOs are about making wholesale power markets function, not just on a day-ahead or hour-ahead basis, but in general on a level playing field in which the cost to consumers -- the ultimate cost to consumers of wholesale power is determined through market transactions as opposed to regulatory determinations. This is a radical break from the historic, traditional way of thinking about utility

regulation, right.

Up until the 1980s it was not really worked, the idea that wholesale power would be determined through market transactions as opposed to regulatory determinations, that is to say, on the basis of competitive prices as opposed to costs.

So my belief, and it's shared by other people who have looked at this, is that an independent system operator is not a viable option for you to consider or propose in terms of promoting economic dispatch. The reason why I say that is because we just do not have enough buyers and sellers of power. As a general matter, you want multiple buyers and multiple sellers, and we are just a very small system. We're thin. We also don't have particularly robust fuel -- competitive fuel markets, right. So the number of producers for fuel used in our generators is relatively sparse, and there's a lot of market concentration there. So, enough said.

This was -- this conclusion, again, is shared by folks who worked on the REGA study and actually a determination of this Commission

back in the early aughts that this is probably not a good way for Alaska to go. So if you want to get away from sort of central planning, you can -- you rely more on sort of market forces to do this.

One way of doing that is to have like a loose pool in which you create a market in which people can and do -- you create a market in which transaction costs for lots of types of transactions of power are reduced so that it's easier for people to transact and get gains from trade in power and power provision, including initially reliability services.

The other approach, of course, is to fully just leave it up to parties to atomistically, organically, spontaneously come together through bilateral contracts, and indeed this is what we've historically seen in the Railbelt. I would suggest to you that in terms of a policy initiative this is not an option open to you, that is to say, leaving it up to bilateral contracts or multilateral contracts is a fine thing to do. It's a reasonable choice to make, but you guys can't help decide which contracts, right. The

decision to allow this is to step back and see where the chips fall. It's not really a policy initiative. It's just a decision. We're going to leave it up to the parties to figure it out as best they can and maybe these will happen; but it's not something that you'd actually be involved in obviously.

So if this is right, it would suggest that -- I mean, there are lots of details to work through, lots and lots in terms of what to do, but you sort of are looking at more or less central planning of some sort, unified operating, and the issues around that are complicated and difficult, or creating more of a loose pool system in which some of the transaction costs around doing deals are reduced. Some of the information -- you create information platforms to help enhance those possibilities and let the participants move forward.

Again, there are an awful lot of details there to work out. All kinds of tariff issues to work out. Lots to do. In general, these are a range in terms of higher levels of coordination to lower levels of coordination,

right. So that's just how it's organized. Some institutions may be more prone to falling short of the ideal outcomes. Loose pools may fail to transmit information adequate to capture the full range of efficiencies. They might. Bilateral contracts, as we've seen historically, can create rigidities that stifle future trades. Once you have a set of institutions, we're bound. If you want to capture new opportunities that if you could unwind those would make everybody better off and the need to unwind is difficult and practically speaking creates a whole set of issues.

We saw that in the Navigant study, right, around Chugach and ML&P's merger. The contractual unwindings that would have been required to help that move forward were -- I think a fair reading indicates it's part of the reason why those efficiencies to the extent that they existed weren't captured. You know, transaction costs are real and shouldering them really matters.

So some of the benefits of sort of central planning or a tight pool or a -- I'm

having -- should say USO, I apologize. Pros: You solve a lot of information coordination problems. You probably capture the greatest degree of dispatch benefits that exist or that can exist, and you've got a platform, sort of a centralized unitary actor platform that might help capture efficient capacity additions. You're further along that route because you've got sort of a point of the spear.

There are some cons. Cons involve transition and operating costs in setting up such an entity. There are material cons in terms of individual utility loss of control. There are real risks that each of the individual utilities would face in terms of how benefits from such a new central planning entity would be distributed amongst them. Then, as well, there is to some degree I think some ideological discomfort with the notion of solving market failure problems through some sort of centralized entity. These are all real.

So let's think about more flexible, less rigid market institutions, loose pool. You know, we'll see what we can capture on any

given day. Transition costs and operation costs might well be lower. They might well -- again, the details are going to matter depending upon exactly what this thing looks like. Each utility is going to be able to maintain more control. What they put into the loose pool to trade, the actions that they are willing to take, remain under the control of the individual utility. This is one of the key hallmarks of a loose pool. Utilities maintain control of their assets, and they voluntarily choose what to do with them.

In that, the risks associated with future governance and the distribution of benefits are avoided. It's not socialistic. They're cons, right. You may not fully solve all the information coordination problems. Some of the dispatch benefits accordingly may be left on the table. This is -- the word no is probably too strong, but I think you probably have less of a platform for efficient capacity additions because all of the information and all of the incentives are not being captured and seen by a central entity.

So I want to belabor a point a

little bit. I got a very helpful e-mail after last week's discussion from somebody who works in a utility who pointed out that least cost dispatch is a complicated problem to solve. It is affected by transmission congestion, which induces losses; in other words, my opportunities are affected by what Bernie does. The multiple actors on the system affect each other's opportunities through transmission losses and transmission congestion.

Gas contracts may have minimum take provisions and maximum take provisions. These are constraints, and each utility's individual gas contracts will create potential constraints on what they do, can and cannot do. So any time you have a constraint and I want to do a trade with you and I do not understand what your constraints are necessarily, that can affect how efficiently we can bargain for favorable outcomes. Security or reliability is obviously a constraint. Allowable omissions on a plant by plant basis are important constraints. Hydro-spill conditions function as constraints. Previous decisions that were made, whether it was last hour or yesterday or

last week or on unit commitments or gas scheduled or must-run contracts, all function as essentially some costs or constraints.

So you have lots and lots of constraints on the system. The ability to efficiently transact and capture savings is enhanced if all of the constraints are fully understood. If they're not fully understood, then you will not be able to optimize. If information around all of these constraints, many of which change from one hour to the next or from one day to the next aren't fully conveyed or readily conveyed, then value may be left on the table.

So it's going to be harder -- any time you have a loose pool voluntary trade environment, it will be as an issue of math harder to get all -- to wring out all of the efficiencies from the system. Having said that, what I've just said is an issue of math and, practically speaking, it's really hard to know how big of a deal that is.

So one possible path, and I call it a scientific path, it's scientific because it's designed to obtain data on the problem or on

the dynamics, would be form a Transco, say. Transition towards postage-stamp rates so that you reduce transaction costs between utilities for what should run, which would facilitate inter-utility trades. Then of course leave dispatch up to the bilateral multilateral decisions of the parties. That's fine. Loose pool, that's fine. But then monitor.

In the Lower 48 regional transmission organizations, ISOs, there are market monitors that assess the degree to which the outcomes in the wholesale competitive markets reflect least cost dispatch. What they're looking for is the potential exercise of market power where the outcomes of competitive wholesale power provisions produce prices that are well in excess of costs.

So we have existing practices in modeling architecture to in a realtime basis compare outcomes against ideal conditions. One can certainly imagine creation of a loose pool in which on essentially a realtime basis optimal dispatch got modeled alongside with a recording of actual dispatch decisions. So long as the outcomes of the two measures were

publicly revealed on a regular and transparent basis, I think you would have a very good opportunity for assessing whether the differences between realized and idealized outcomes, assuming they occurred, were sufficient to transition further from a loose pool to potentially a tight pool.

I can absolutely envision a world in which they were not. One of the things that market monitoring has regularly shown in the Lower 48 is that competitive wholesale power markets often have done astonishingly well at coming -- at approaching the very least cost possible solution. And compared with the alternative, which involves shouldering a bunch of regulatory costs, you know, that's a much better place to be. The alternative of a loose pool here as envisioned might well entail a bunch of additional institutional architecture and costs and some loss of nonbill values, and shouldering those might not be worth the incremental gains. They might. But if you have these data transparent, then at least it would help solve some of the market failure problems around some of the monopoly provision

of service to customers, customers not being able to show what they most prefer in the marketplace by moving, right, because we're all essentially captive customers.

I'm not advocating this path. It's just available. If you were interested in suggesting formation of a loose pool, I guess what I'm really saying is my recommendation is going down that path we're more likely to get where we ultimately want to be either in terms of institutions or market outcomes if we've got transparent sharing of the information that gets generated in terms of realizations and modeled best outcomes.

Now, you could also absolutely jump to a formation of a tight pool or a USO. I think one of the biggest issues that shows up there is the risks that everybody perceives around governance and how benefits would be distributed. These are issues which are being negotiated now, as I understand it, or at least talked about, and that is a very good thing. It will be a process. When I say jump, that's really a misnomer, because no matter what you're looking at a process for figuring this

out. But the issue of governance is particularly important when we look at forming any of these new institutions, whether it's a Transco, but especially if we're looking at formation of a tight pool or a unified system operator.

That's a subject which we're going to focus on particularly next time in terms of looking at different governance structures in the Lower 48 and thinking through how some of those governance models do or do not well match our current circumstances here in the Railbelt.

With that, finally, I'm done.

CHAIRMAN PICKETT: Thank you. I think one thing that would probably be helpful for both the Commission and in the context of our final report is the definitional section. I say that because I've had a number of conversations with legislators in some depth, and there is very much of a blending between ISO-ism, USO, Transco. It's almost like for some it's just this interchangeable term, where that clearly is not the case. When I use USO, I'm sort of using a very blended thing in my own mind, but I think we're going to need to

really get that nailed down here.

DR. SCOTT: So I think that's incredibly important. I would say, as I've observed before, these magic words and meaning changes over time. I mean, if you go back and read documents from the 1990s, the words and the meanings are different from how they're often used today. It is appropriate and necessary for anything that we provide to you guys in writing to at least try to define what it is we're trying to carve off just in terms of meanings of these terms. Whatever we do will offend somebody because they'll say, no, that's not what that means. This means that. So it needs to be understood that what we're doing is trying to come up with definitions for our purposes, just so we understand each other. But, yes, I agree. I think this is very important.

CHAIRMAN PICKETT: And I also think there needs to be a discussion on what restructured markets actually are in the Lower 48, and the fact that the reality, given our statutory construct with the co-ops and municipally owned utilities, that a fully

restructured market in the Railbelt is probably something that is not particularly attainable.

DR. SCOTT: That part's been written.

CHAIRMAN PICKETT: Are there other Commissioner questions before we wind up today?

Dr. Scott, we will look forward to seeing you at the next special public meeting next Wednesday the 20th for a continuation, and governance issues will come to the forefront.

DR. SCOTT: Thanks very much, Mr. Chairman.

Again, I want to thank especially Chris Pike for the work that he's done on this project, especially in terms of putting together the generation addition story that we've been telling today.

Next week you will hear particularly as well from Erin Whitney. Erin's also been working on this project. She's done a lot of work around the governance issues. So she'll actually be making at least some of the presentation next week. So I've been the dumb guy who's had to sit up front, but I couldn't have done it without an awful lot of hard work

from other folks as well.

CHAIRMAN PICKETT: Okay. Thank you. That will close agenda item No. 3.

Agenda item No. 4 is other business. I have no other business. Do any of the other Commissioners? Agenda item No. 4 is closed.

No. 5, executive session. Does the attorney general have need for an executive session?

MS. POKON: No.

CHAIRMAN PICKETT: Is there a motion to adjourn at approximately 11:39 a.m?

COMMISSIONER McALPINE: So moved.

CHAIRMAN PICKETT: Second?

COMMISSIONER WILSON: Second.

CHAIRMAN PICKETT: All those in favor of adjourning say aye.

COMMISSIONERS: Aye.

CHAIRMAN PICKETT: Thank you for being here this morning.

(Concluded - 11:39 a.m.)

I-15-001
Alaska Railbelt Electricity System

More high-level modeling of some benefits of change

5/13/2015

ACEP
Alaska Center for Energy and Power

Legislative Charge

RCA should recommend:

Whether creating an independent system operator or similar structure for electric utilities in the Railbelt area is the best option for effective and efficient electrical transmission.

Overview

- Review modeled 'net benefits' in 2026 of new transmission with economic dispatch
- Discuss Railbelt reliability benefits that new institutions might promote
- Discuss evidence of benefits that coordinated Railbelt capacity additions might promote

Standard modeling caveats

- AEA study was good but still relatively high level (+/- 25% accuracy)
- Have to 'kludge-adjust' 2020 dispatch benefits to 2026 transmission tariffs
  - Probably serves to understate benefits
- Economic dispatch benefits determined by uncertain future events
- Only some dispatch benefits are captured here:
  - No power regulation benefits
  - No benefits from optimal Bradley dispatch

Net Benefit Tariff Sensitivities
All AEA Transmission Additions

	Base	70/30 D/E	No AFUDC	3% COD
All Pre-Watana Transmission Upgrades	149.36	136.95	128.38	138.70
ACEP "Base Case" Economic Dispatch Benefits (2026)	95.39	95.39	95.39	95.39
Net costs to ratepayers (millions)	53.98	41.56	32.99	43.31
% of today's total costs	5.8%	4.5%	3.6%	4.7%

Benefits calculated for year 2026
Benefits *highly* approximate

Net Benefit Tariff Sensitivities
North & Central Transmission Additions

	Base	70/30 D/E	No AFUDC	3% COD
Northern & Central Project costs	86.36	79.23	74.65	80.24
ACEP "Base Case" Economic Dispatch Benefits (2026)	83.18	83.18	83.18	83.18
Net costs to ratepayers (millions)	3.18	-3.95	-8.53	-2.94
% of today's total costs	0.3%	-0.4%	-0.9%	-0.3%

Benefits calculated for year 2026
Benefits *highly* approximate

Net Benefit Fuel Price Sensitivities North & Central Transmission Additions

	ACEP Base Case	North Slope PL for all	Cheap trucked gas to	Imported LNG, $110 oil
Northern & Central Project costs (lower COD case)	80.24	80.24	80.24	80.24
ACEP Economic Dispatch Benefits (2026)	83.18	57.90	43.27	92.12
Net costs to ratepayers (millions)	-2.94	22.34	36.97	-11.88
% of today's total costs	-0.3%	2.4%	4.0%	-1.3%

Benefits calculated for year 2026
Benefits *highly* approximate

Scott's Efficiency Theorem

- *If different institutions could cause more "efficient electrical transmission" then market failures exist*
- Sources of market failure:
  - Information may not be perfect
  - The existing institutions may entail greater transaction costs to solve things bilaterally
  - There are externalities
- Existence of market failures gives RCA a necessary role

Reliability value of N-1 Transmission?

- One approximation: The *cost* of getting there without transmission additions
  - Model "non-pooled, non-transmission addition" case in which each utility carries spin at its own largest generation contingency
- Incremental cost of carrying largest generation contingency spin totals ~$74 million in 2020

GVEA's reliability "stated preference"

- Benefits of Northern transmission upgrades declines if NPCC is "must run" in winter
- Base case savings fall from $79.5 to $64.3 million
  - Implicit, high ($15 MM/year) value on reliability
  - ~140 Intertie trips (Teeland-Douglas, Douglas-Healy) from 1990-2014, none appear to have causes that would trip a redundant transmission system
- Actual preference may be less than stated preference

Who should determine 'right' level of reliability?

- Do customers convey reliability expectations, with management following?
- Utilities, practically speaking, now condition level of reliability their customers demand
- Commission has statutory authority within (and possibly across) service territory

Transmission build and market failures

- "Free Rider" problem: when benefits can be enjoyed by someone who does not pay its full cost
- FERC Order 1000 replete with discussion of this, eg

  [T] he free rider problems associated with new transmission investment is particularly high for projects that affect multiple utilities' transmission systems and therefore may have multiple beneficiaries. With respect to such projects, any individual beneficiary has an incentive to defer investment in the hopes that other beneficiaries will value the project enough to fund its development.

Railbelt transmission business case

- Railbelt has no business model for constructing transmission assets that provide shared benefits on a "non-firm" basis
- All risk of non-recovery borne by native load ratepayers
- Recovering from non-native load ratepayers causes transmission rate "pancaking", distorting economic dispatch

Prediction of reliability decline: The missing business model

- CEA's 230 kV submarine cables between SPP station and Point Mackenzie
  - 40 years old
  - Primary transmission path for energy from Anchorage/Kenai towards GVEA
  - Failure would affect MEA/GVEA reliability
- Possible but difficult for MEA/GVEA/CEA to solve incentive and coordination problem
  - Requires pro-active problem solving
  - Requires not hoping/lobbying Legislature to solve

Railbelt Capacity Overbuild? Evidence from Past Studies

- In 2007-2008 public recognition of:
  - MEA and HEA had exercised options to stop being requirements wholesale customers of CEA
  - Tight natural gas supplies in Cook Inlet
- How to plan for new generation?
- What to plan for new generation?

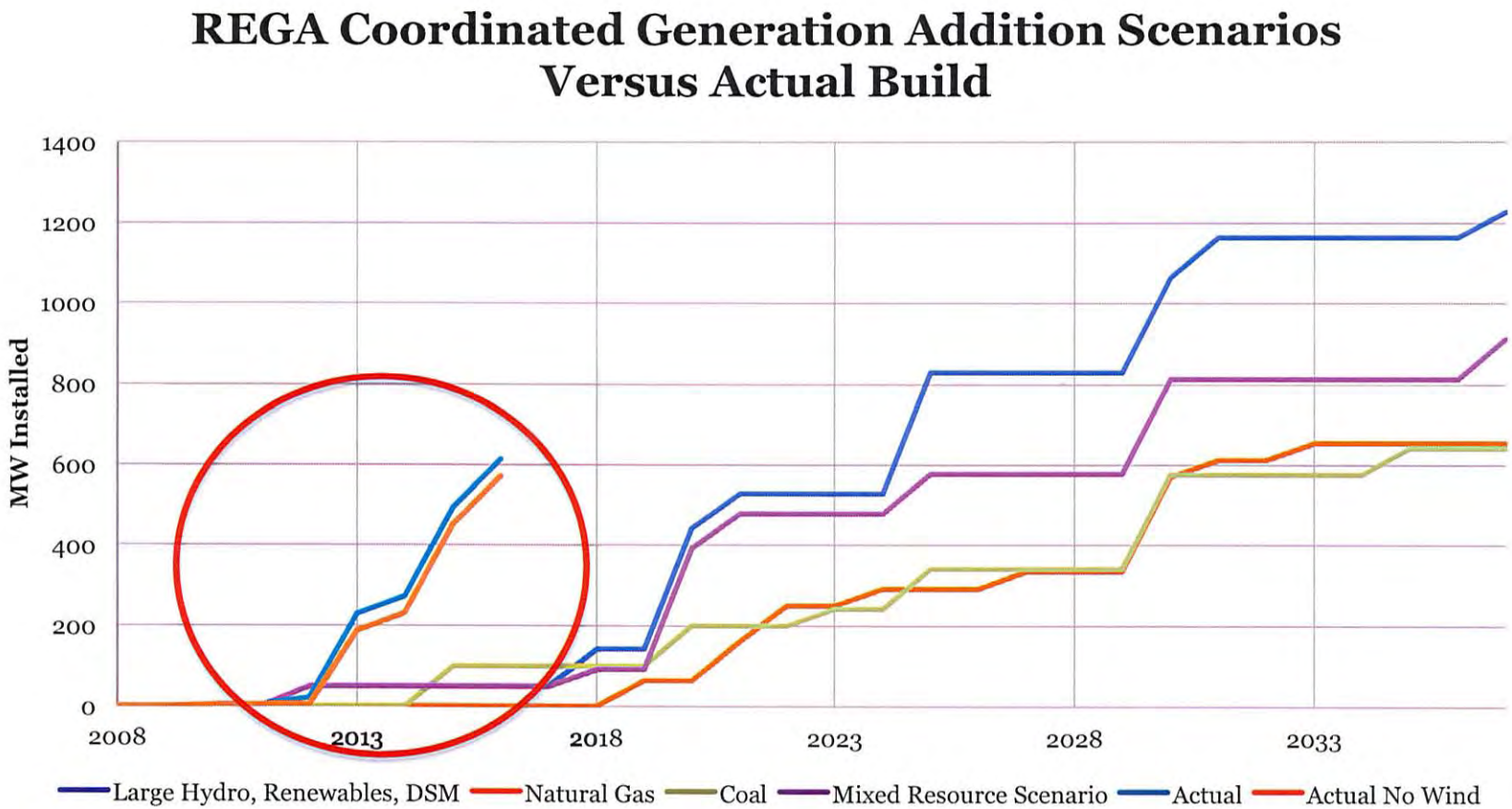
What did (and will) happen?

Year	Project	Installed Capacity (MW)
2010	Seward Diesel Gensets	5.3
2012	Fire Island Phase 1	18
2013	Southcentral Power Plant	142.1
2013	Nikiski Cogeneration	40
2013	Eva Creek	24.6
2014	Soldotna	44
2015	Eklutna Generation Station	171
2015	Healy #2	50
2016	Sullivan 2A	120
Total		**615**

What might have happened? REGA Study

- AEA sponsors the Black & Veatch Railbelt Electrical Grid Authority (REGA) study
  - Forecast future demand
  - Determine capacity additions that most cost effectively meet forecast demand for different resource mixes
- Material savings from central coordination of generation and transmission construction
  - Recommends formation of a G&T
  - Echo's B&V's 1998 study, which found material benefits from joint construction planning

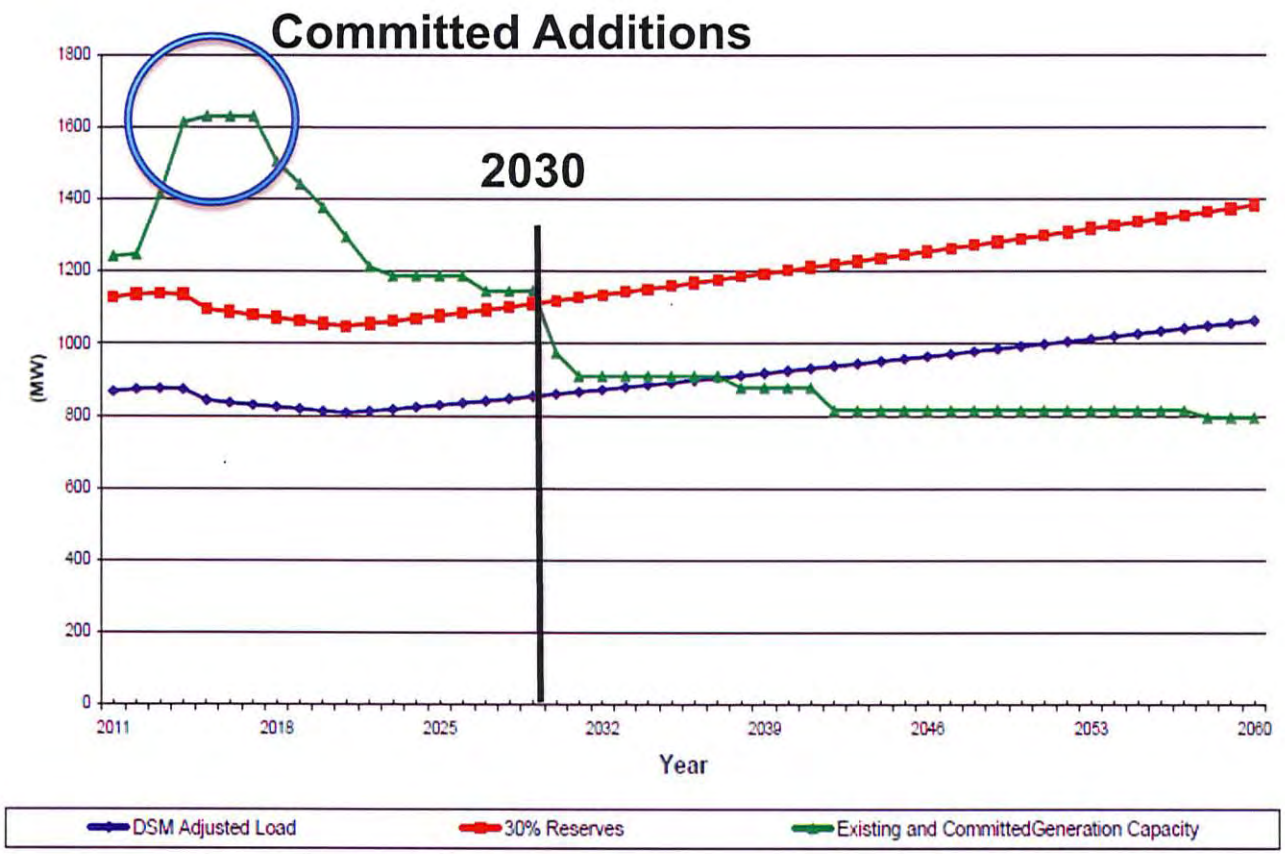
Atomistic Results vs Coordinated Plans



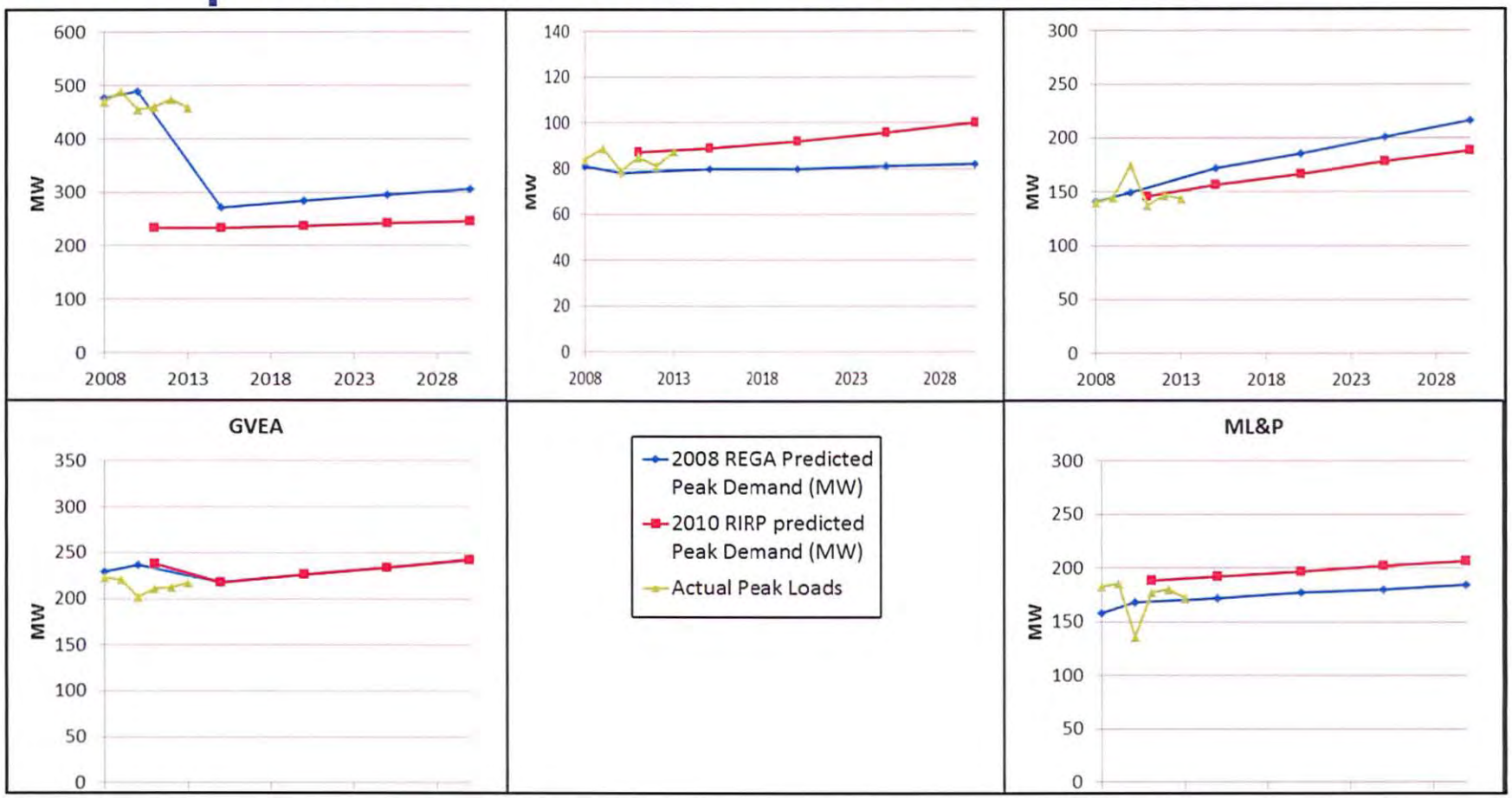
Railbelt IRP Study (2010)

- Same approach as with REGA study
  - Forecast future demand
  - Determine capacity additions that most cost effectively meet forecast demand for different resource mixes
  - Assume economic dispatch
- Existing capacity commitments 'built in' to forecasted need for new capacity

RIRP confirms atomistic planning 'overbuild'



Capacity Additions: B&V peak load forecasts reasonable?



Capacity Additions
How Imperfect Information Matters

"Before we built the unit at Soldotna, Chugach suggested, unfortunately too late, that we put that unit at Beluga. Homer would own it, it would be physically located in Beluga so it's not competing with tie line space coming up here, it would have been used more and we would have gotten greater value out of it. Unfortunately we were too far down that road of building it at Soldotna to reverse course, but it is a good idea."

Harvey Ambrose, HEA; Legislative roundtable, 9/5/2014

Getting to Economic Dispatch (redux)

- In principle can achieve more than one way
  - ~~One owner (e.g. REGA/GREFC concepts)~~
  - Tight pool/USO (1998 B&V, REGA, CH2M Hill)
  - ~~ISO~~
  - Loose pools
  - ~~Bi-lateral contracts (e.g. historical MEA-CEA, HEA-CEA, Bradley Lk CEA-GVEA dispatch agreements)~~
- Some institutions may fall short of ideal
  - Loose pools may fail to transmit information adequate to capture the full range of efficiencies
  - Bi-lateral contracts can create rigidities that stifle future trades

Strikeouts indicate non-viable *policy* initiatives; bi-laterals may be market viable

Two possible policy approaches towards economic dispatch

- "Central planning", e.g. "tight pool" or ISO
  - Pros:
    - Solves information and coordination problems
    - Captures greatest degree of dispatch benefits
    - Platform for efficient capacity additions
  - Cons:
    - Transition and operation costs
    - Loss of control
    - Governance risks (distribution of benefits)
    - Ideological positions

Two possible policy approaches towards economic dispatch

- Flexible market institutions (loose pool)
  - Pros:
    - Low transition and operation costs
    - Each utility maintains more control
    - Governance risks avoided
    - Not socialistic
  - Cons:
    - May not fully solve information and coordination problems
    - Some dispatch benefits will be 'left on the table'
    - No platform for efficient capacity additions

Imperfect info should affect loose pool results

- Least cost dispatch will be affected by:
  - Transmission congestion (which induces losses)
  - Minimum takes of gas contracts
  - Maximum takes of gas contracts
  - Security (reliability)
  - Allowable emissions
  - Hydro spill conditions
  - Previous decisions (e.g. unit commitments made, gas scheduled, must run contracts)
- Harder for two parties to have the full relevant information set than just one

One highly stylized "scientific" path: Transco to loose pool to (possible) USO

- Form Transco
- Institute transition towards postage-stamp rates
- Have Transco perform "market monitor" duties:
  - Model real-time 'optimal' dispatch
  - Collect real-time information on actual dispatch
  - Public, transparent utility-by-utility posting of differences
  - If differences do not support costs of a USO then loose pool might be "best" solution

A direct jump to "tight pool"/USO?

- Some of the biggest challenges to formation of a tight pool or USO involve governance questions
- Subject to which we'll turn next time

ACEP
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Questions?

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STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners: Robert M. Pickett, Chairman
Stephen McAlpine
T. W. Patch
Norman Rokeberg
Janis W. Wilson

REGULATORY COMMISSION OF ALASKA
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501

Special Public Meeting
May 20, 2015
9:00 a.m.

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P R O C E E D I N G S

(On record - 9:01 a.m.)

CHAIRMAN PICKETT: Good morning. This is the special public meeting of the Regulatory Commission of Alaska. It's Wednesday, May the 20th, 2015, approximately 9:02 a.m. With me on the dais are Commissioner Norman Rokeberg, Commissioner T. W. Patch, Commissioner Stephen McAlpine and Commissioner Janis Wilson. And I'm Bob Pickett, Chairman of the Commission.

Agenda item number 1 is public participation. Is there anyone in the Anchorage audience who would care to address the Commission this morning?

Seeing none I will turn to anyone online. Is there anyone online when would care to make any comments or address the Commission on any matter this morning?

Hearing none, we will close agenda item number 1. Agenda item number 2, I-15-001, in the matter of the evaluation of the operation and regulation of the Alaska Railbelt electric transmission system.

I will turn to Dr. Scott. I see we have a new face at the front table. So do the introductions.

DR. SCOTT: Good morning, Mr. Chairman, Commissioners. You get two presentations today. The first will be by Erin Whitney. Erin is a researcher/professor at the University of Alaska, Fairbanks and has been working on this project, as I mentioned last time. So I'll leave it to Erin to introduce herself and start.

MS. WHITNEY: Thank you. Can everyone hear me okay? Great.

Thank you, Commissioners. My name is Erin Whitney. I am a researcher at the University of Alaska at Fairbanks with the Alaska Center For Energy and Power, as Antony mentioned. Today we'll be talking about governance structures and issues with unified system operators as they pertain to --

CHAIRMAN PICKETT: Could you put the microphone a little closer to your mouth and make sure the green light is on.

MS. WHITNEY: The green light is on. How is that? Are we set? Okay.

CHAIRMAN PICKETT: Bernie, could you help with the overhead screens?

I'll tell you what. Let's proceed. We have

the PowerPoint presentations. We can follow and look at the screen in the front and hopefully we'll get the two overhead ones going.

So, Erin, please continue.

MS. WHITNEY: Okay. Thank you. Today's is the last session in a series of presentations by the Alaska Center for Energy and Power associated with the Alaska State Legislature's charge to the RCA of whether creating an independent system operator or similar structure for electric utilities in the Railbelt area is the best option for effective and efficient electrical transmission.

As I give the presentation today, my colleague, Antony, who you heard from the last couple weeks may interject a time or two. I'll start on slide three here by reusing some of Antony's slides from last week where he discussed some of the modeled benefits of economic dispatch. And I'm doing this as a way of setting up the motivation for today's discussion.

Achieving economic dispatch can be established through a number of routes. Last time the concept of one owner was introduced and dismissed. The concept of a tight pool or a

unified system operator as well as an independent system operator were also discussed. It should be noted that the ISO option was dismissed. Loose pools and bi-lateral contracts were discussed. Bi-lateral contracts were dismissed as a policy option because of some of the rigidities involved.

It should be noted that some of these institutions may fall short of the ideal for various reasons, but this slide is to point out the two policy options that were narrowed in on last week comprise the loose pool and the tight pool for a unified system operator.

The loose pool pros and cons were discussed. When talking about a loose pool, the issue of governance is not so relevant. But when talking about a tight pool or a central planning situation -- also termed a unified system operator -- governance does become an issue. And that's why we're talking about today's topic. We're going to go down this rabbit hole a bit and peel back some of the layers to look at what some of the relevant issues may be for governance of such an entity.

Why does governance matter? Who decides, who decides? Governance is about making key decisions

for the players involved. It critically affects the distribution of benefits for the players and the risks involved. And at its core, it's the balance between taking away some control from the players as well as providing the players, in this case the Railbelt utilities, investment in the governing structure, a voice so that they can be heard at the decision-making table, as well as creating channels for utilities and players to transfer the technical expertise that they absolutely have in the operation and management of the electrical system.

There are a number of lessons we can learn from independent system operators and regional transmission organizations in the Lower 48. And I preface this slide by emphasizing that we're not saying that an ISO is necessarily the route for Alaska or the Railbelt, but simply that they have some organizational and governance structures from which we can learn some lessons for an appropriate entity up here.

ISO's and RTO's were formed as a result of Federal Energy Regulatory Commission Orders 888 and 889 in 1996, followed by Order 2000 in 1999. All of this is to say that these issues have been

thought about for some time. People have been grappling with these organizations and how to make them most effectively function.

The issues around ISO's and RTO's in the Lower 48 are different from those of the Railbelt. They generally revolve around keeping transmission operation independent from generator interest with a core motivation to ensure a robust and competitive wholesale electricity market. And, again, I stress that an ISO or an RTO is probably not appropriate for Alaska, but we will extract some useful lessons from their existing governance structures.

This is an illustration of ISO's and their service areas in the Lower 48. There are six ISO's regulated by FERC in addition to ERCOT, the Electric Reliability Council of Texas, which is not regulated by FERC because it does not cross state boundaries.

Of note in this illustration, Midwest ISO's name is actually now Midcontinent ISO, but its service area is still the same. Just to give you a sense of the scale of the loads that these organizations handle, PJM there in red, its annual load size is about 800 million megawatt hours.

And that ranges all the way down to the smallest ISO load, which is that of ISO New England, which is about 130 million megawatt hours.

If you compare that to the Railbelt load, all of those are several orders of magnitude larger than our load, which is about 5 million megawatt hours. So some big differences in the markets and the circumstances there. And, also, the number of players. It should be emphasized that these ISO's have hundreds of members, utilities, generators, et cetera.

What are the functions of these organizations? They have a number of functions that can encompass part or all of this list here. They're involved in market management, that is conducting auctions which give participants the price signals to match scheduled load with expected demand. They can also be involved in market monitoring, that is maintaining market discipline based upon monitoring for and enforcement of sanctions for that abuse.

These are probably not appropriate functions for an entity up here. So other responsibilities of these organizations include dispatch, that is determining the command to turn on, to turn off,

to hold in readiness, or repair significant generating units. There's also transmission scheduling, that is the decisions to open, to close, or reserve transmission lines, and to schedule, implement, or defer desired maintenance.

There's also the operation of the open access transmission tariff. There are planning activities. The projection of expected demand and potential and preferred ways of meeting that demand. And then, finally, collecting the revenue through charges on the use of monopoly wires to be distributed to transmission owners in ways that will compensate past and incentivize future investment.

So before we dive into a couple specific examples of these ISO's and their governance structures, I want to highlight several key considerations that end up being themes through these specific examples. One is the independence in board structure. All of these ISO's have an independent decision-making board. It's very important that this board have its objectivity and independence from stakeholders and members so that it's not unduly influenced. And also to ensure no self-dealing between the board decisions and

affiliated parties.

And that independence can be achieved through strategies aimed at the composition of the board, selection of the board members, whether they're appointed, whether they're member elected, how the board members exit, how they're terminated, and the qualifications of the board members.

The qualifications can be particularly tricky, because, typically, the people who have the qualifications to serve on these boards, have affiliations and experience in the industry. So that's something also to keep in mind.

In addition to having these independent decision-making boards, these ISO's also have, typically, an advisory committee or an advisory council that serves to provide technical expertise on selected matters and articulate the interests of stakeholders and members. The advisory councils have their own specific voting procedures, which we'll get into. And, again, there's the issue of qualifications.

And then as we talk about boards and advisory councils a key issue becomes the division of authority between these two parties. So we have an independent decision-making board. How much

authority does that advisory council have? And we have examples of cases where the advisory committee has no legal authority; they simply consult. And there's also an example where the advisory council has some shared governance with the board. So we'll highlight all of these.

ISO New England is arguably the purest of the ISO's in its structures. And I should emphasize here that these are highly simplified diagrams of the ISO organizations. The entire organization is more like a Medusa picture. But these are intended to highlight the salient issues for the lessons that we might transfer to the creation of an appropriate entity here in the Railbelt.

In the case of ISO-NE there's a ten-person self-renewing board. Self-renewing means that the board elects its own members. And membership in the board here means no affiliated interest with the members and stakeholders of the ISO. So an objective decision-making authority. There is a participants committee that represents the stakeholders.

And it should be pointed out that this committee represents over 200 entities. A huge number of members and interests represented here.

The participants committee has an advisory role, but no legal authority over the board. And its voting procedures -- the participants committee voting procedures are done on a sector-weighted basis. So members elect to be part of one of six sectors which are broadly classified categories of the market. In the case of ISO-New England, those sectors are generation, transmission, suppliers, alternative resources, publicly owned entities, and end users.

And the way the voting works is that each sector has an equal vote or an equal weight. And this is important because if one sector has a large number of members, it prevents one sector from overwhelming or capturing the vote of the entire participants committee.

And then peeling that back even more, within each sector -- each sector's vote is divided into an affirmative and a negative fraction based on the corresponding fraction of votes of its members. So that's what we mean by sector-weighted voting. Virtually all of the ISO's use that structure in their committee voting procedures.

Moving to another example, the New York ISO

also has a self-renewing board where the membership means no affiliated interest. There is a management committee that advises the board. Critical differences here is that in addition to representing market participants, public interest groups get a voting weight on this management committee. Voting sectors, as we discussed, are also used here.

And, also, this committee has shared governance with the board. So that is to say that approvals of both bodies are required for a filing to take effect. It's much like a two-house system in our current form of government. And there are some weaknesses to that. It adds a vulnerability to gridlock. So we'll come back to that when we talk about lessons for a Railbelt entity.

The California ISO is yet another example. It's a smaller board. Bored members are appointed by the governor. They have, I think, staggered three-year terms. Again, membership means the no affiliated interest. And the advising committees have no legal authority over the board and their membership is appointed by the board.

The final example I want to highlight is that of the Electric Reliability Council of Texas,

which is its own breed of organization. Its board is more of a hybrid composition, meaning that we don't have that complete independence and lack of affiliated -- affiliation that we saw in the other boards. It's comprised instead of market representatives. It's comprised of consumers, as well as these independent members. So it has a much more mixed composition. Again, there's an advisory committee comprised of representatives of stakeholders to consult on technical matters and provide technical expertise when needed.

So what are some of the lessons from these governance structures that we might apply to an appropriate entity in the Railbelt, if that is the direction that is pursued? Critically, the utilities may insist on maintaining a direct voice. This need for direct voice has been seen in the formation of GRETC and in several efforts by the Railbelt utilities to solve utility coordination challenges on their own. Also as a precedent, utility representatives currently participate in management committees for State-owned projects such as Bradley Lake in the intertie operating committee. They already have a seat at the table of these various projects.

Given that they may need to have a direct voice, the government body may need to be structured to ensure that no single party can capture decision-making functions. So this is a slightly different type of independence. You know, there are fears, quite frankly, out there that Chugach, the largest utility, could take over and try to run the whole show. And this points to a history of distrust among some of the utilities. Added to that are uneven levels of in-house expertise within the utilities that contribute to the governance structure.

So how might we accomplish this type of independence for a governing body? One approach might be to give any one party or any one utility veto power. They can shut it down just like that. Or another approach could be to dilute those voting rights to prevent undue influence.

And this could be as simple as making the governing body number twice that -- at least twice that of the number of utility representatives. How might you fill out that governing body with non-utility representatives? You could have RCA ex-officio membership. There could be representation from a TRANSCO, should that come to

fruition. There could be representation from independent power producers as well as other non-utility interests, which we certainly see in other ISO's in the Lower 48. Those could involve residential and commercial consumer representatives, public interests, environment groups, conservationists, et cetera. There are any number of variations on some of those options.

Quite critically for the board, to ensure against the capture of non-utility members, board membership, if it is initiated and in use, may need to be substantially compensated and highly qualified. Highly qualified representatives could definitely come from within the state. They could also come from outside the state. And I think the process should be open to that.

I want to finally address the issue of an advisory committee since we see the presence of those in all the ISO's in the Lower 48. It's probably a good idea to have something like that for a governing entity in the Railbelt. It provides a channel for transferring technical advice from the utilities themselves. It broadens the base for receiving and collecting technical expertise. And it increases opportunities for

stakeholder input, you know, which as we've discussed, you know, increases the investment in the governing system.

We might recommend against giving the advisory committee decision-making authority. As I mentioned in the case of the New York ISO, that shared governance between the advisory committee and the board creates a vulnerability for gridlock. And there may also be a perceived vulnerability to capture due to uneven distribution of technical expertise within the advisory committee.

So those are the very brief takeaways from a survey of ISO's and RTO's in the Lower 48. And at this point I'll open it up to any additional comments from Antony or questions from any of you.

CHAIRMAN PICKETT: Antony, did you have any comments before we go to Commissioner questions?

Commissioner questions?

Well, I think the governance is -- if any sort of entity does emerge from this process, is going to be incredibly challenging given the history; and I think you identified the distrust. And just different ideas about how to approach it.

So I appreciate what you have done. And we will be working with you over the next couple of weeks to refine this.

MS. WHITNEY: Thank you.

CHAIRMAN PICKETT: So I think the ball is in your court now, Antony.

DR. SCOTT: Good morning. For the record, my name is on Antony Scott. I'm with the Alaska Center for Energy and Power. I'm very pleased that this is the last one of these that we get to do.

I want to thank, actually, the Commission very much for the opportunity -- I mean, having said that, for the opportunity to play in this game. It's been an exceptionally rich learning experience for me, I know. And, also, incredibly difficult. The subject is super wide and super deep. So apologies at the close for not knowing more and being able to do better. But it is what it is.

So, as you know, this is your charge. Your job is to make a recommendation. The recommendation concerns effective and efficient provision of electricity in the Railbelt. I would submit that it is up to you to decide what

effective and efficient means, to give meaning to those phrases, and also to make determinations as to whether we are sufficiently efficient and effective today to meet the overall larger goals of the provision of this necessary service to the public.

We started awhile back asking the following question: Are there reasons for thinking that the Railbelt is less than efficient? How would you measure efficiency? Well, some standard ways of measuring efficiency involve the short-run efficiency of economic dispatch using the resources that you have today most effectively and efficiently, that is at least cost overall.

Efficiency with regard to long-run costs, generation planning and construction, or transmission planning and construction, service reliability. And then, as well, there are other goods besides electricity itself or other aspects of the provision of electricity that people may care about. Namely, whether we're doing it ourselves or not, whether in purchasing it from somebody else we think that they may be taking advantage of their circumstance.

These are valid -- again, non-billed values

are valid and reasonable things to care about. They're not easily put on the same scale as the simple cost per kilowatt hour. So before getting into a recap of reasons for thinking why the current system, at least considered globally and from the narrow perspective of cost, may not be the most efficient and effective system we have. I want to share with you my experience of recently reading an order which was issued by this body's predecessor agency in 1985.

I thought that the discussion around, you know, more efficient and effective organization within the Railbelt was actually relatively recent. You know, sort of 1998. Just shows you what a newcomer I am. It predates that considerably. In 1985, this order was issued, which was the resolution of a docket which was opened in '82, as you can see.

And in the discussion -- we don't need to get into the guts of the order. But in the discussion of the order it involved whether the Commission should require Chugach to form a GNT which would include Homer and MEA and Chugach. We see thematically all of the same stuff we're dealing with today. The details are different, but the

theme's the same. There's discussion around potential gains from more coordination, that is to say more efficient provision of electricity.

There's questions about the Commission's authority to push or enforce a new set of institutions to realize gains. There's discussion of at that point the historical animosity among the parties. There's discussion explicitly within the order of the influence on the utility boards by their management, and what their management does and doesn't tell the boards or inform them or steer them.

Whether the Commission is right or wrong, this is a series of perceptions that I haven't spoken to before that are nevertheless widely -- well, I wouldn't -- maybe wide is too strong. But these are perceptions that many people have in observing the industry historically. Again, right, wrong, or indifferent, this is a set of perceptions.

The next-to-last one I thought was pretty interesting because we see this move regularly. The Commission notes that they've been told that, you know, we've got HEA, MEA, and Chugach boards mutually agreed to form a GNT. Like, don't push

us. Don't tell us what to do. We're on track to do it ourselves. That's not quite how it worked out. We saw this in GRETC. We've seen it over and over again. Don't make us. We'll do it.

I'm not suggesting anybody is trying to hide the ball. I don't think that's the case. I think what this speaks to is it's very difficult for multi-parties -- multiple parties to voluntarily self-organize and keep the ball going to ultimately realize all of the differences among themselves in a purely voluntary way.

(Phone rings.)

CHAIRMAN PICKETT: Please mute your phone if you're online.

DR. SCOTT: The last thing that I wanted to -- that I remarked in reading this order is this order deals in part with difficulties in securing capital to make needed improvements, that is financial straits that Chugach at the time found itself in. And, obviously, they navigated their way out.

The issue of capital attraction is not normally one that I'm aware of that utilities -- certainly investor-owned utilities, I could say that at least -- in the Lower 48 find themselves

in a position to struggle with. Capital attraction, generally, is not a problem. The reason why is these are, in general, regulated monopolies. We're dealing with a necessary service. You have captive customers purchasing a necessary service, which is a really good business place to be.

Either this speaks to problems about the Commission or problems with how co-ops attract capital from various federal entities; but, you know, I find it surprising that people point to the difficulty of raising capital in this industry. It shouldn't be particularly difficult, because, again, at the end of the day, you've got a captive customer base. I mean, I understand that there are real-world constraints, but it's relatively straightforward for many other organizations to acquire the capital that's needed.

The reason I'm spending a little time on this right now is because as we'll see -- as we see today, we've had people recently in the last year come before this Commission and explain that they are tapped out in terms of their ability to raise capital to make necessary improvements; and they

need the State or some other entity to help out with that.

It's unclear to me why we couldn't form institutions that would avoid that sort of circumstance. Okay. Are there reasons for thinking that maybe we are not fully efficient or as efficient as we might be from the perspective of cost alone considered globally? Well, let's look at economic dispatch. On the one hand, it's very important to stress there are significant transactions occurring toe, have been for a long time around economy to energy sales. Those transactions benefit all parties.

Really the question is not whether trades are occurring or have occurred. The question is whether there are increased gains that might be wrung out of the system. There's a long history of modeling which indicates that there are increased gains that indeed probably could be wrung out of the system. And we talked a little bit last time about why that might be the case, even if we don't engage in significant transmission upgrades.

I mean, that's the result that Black & Veatch found in '98 and again later CH2M Hill and,

certainly, what we've found in our own modeling. Are those increases, are those gains from economic dispatch available without new infrastructure investment in transmission? Massive? No. They're actually not. They're pretty modest. They're pretty modest. They're material, but they're modest.

Larger gains are probably only possible with more robust transmission infrastructure, which then immediately raises the question, well, wait a minute. That's fine. But that transmission infrastructure's long lead time is quite expensive. Just because you could get more economic dispatch if you built it, doesn't necessarily mean that you should build it. And I think that's a fair point.

The results that we discussed last time indicated that from a global perspective, it is probably not a barn burner to go out and construct a whole bunch of new transmission for purposes of capturing economic dispatch gains. But it's also unlikely to be a massive burden either. The stakes either way are comparatively modest.

That doesn't mean that we should do -- you know, that we should engage in building or

constructing anything. However, again, as we pointed out last time, it is almost certainly the case that increased transmission infrastructure would provide improved reliability, system resiliency, and optionality. It would facilitate -- it would create opportunities for facilitating economic growth for extending the system overall. It would help, possibly, with the overall resilience of the system from a human capital perspective.

So let's talk about generation planning and construction. Again, it's important to note that today and historically there is and has been inter-utility cooperation. SPP plant's a good example. However, it's also the case that the atomistic responsibility for generation investment appears to have been inefficient compared with the results of what would have occurred had there been joint planning to jointly meet the Railbelt's needs.

Modern results indicate this and informal conversations that I've had with utility people -- executives is the wrong word. Well, management. How's that -- supports this.

Today it's also worth noting that the RCA

lacks statutorily the tools to promote regional efficiencies. Right now you have atomistic, that is to say utility by utility integrated resource planning. But you do not have authority to force global planning. I mean, you could make the utilities, I suppose, come in and come up with a global plan; but nobody would have to follow it. And that's because you do not have the ability to say: Stop. You can't build something unless it's consistent with a regional IRP.

And without that minimum ability to at least do that, you actually don't have any real traction to force a regional planning process to ensure that joint planning gains can be captured.

Transmission planning and construction. Well, we talked again last time about free rider problems. Those free rider problems are pretty well documented outside the Lower 48. In general, they lead to underinvestment. They're caused by the fact that if I take responsibility and build transmission that benefits my ratepayers but is an inter-utility transmission asset and Erin's ratepayers can't benefit, she's not very likely to want to pay for that infrastructure.

So even in the event that I go ahead and

build it, then I come to the Commission and then we get to have a vicious argument around cost allocation and who benefits how much from that system at any given point in time.

And, as I think you're more than familiar with, those sorts of arguments are not analytically tractable. That is to say, there is not a simple answer that is the result of math. We also talked the last time about there's no ready Railbelt business model to support inter-utility transmission planning and construction. We don't right now have firm bi-lateral contracts to support inter-utility transmission. And we don't have a unified Railbelt TRANSCO.

And we do have existing transmission assets now that provide joint benefits among several utilities from a reliability perspective. And it's unclear whether on a purely voluntary multilateral basis we will see the forward-looking investment that needs to occur to ensure that those assets are adequately, timely replaced.

We also talked about reliability. I think everybody recognizes that the Railbelt utility provisioning of electricity -- of reliable

electricity has substantially improved from 30 years ago or even 20 years ago. That's what casual observation suggests, and it's probably very clearly the case.

But I think it's worth asking also more broadly, good compared to what? It's good compared to sometime ago, but are we good compared to other systems? And we reviewed how I can't tell you that one way or the other, and I'm not sure that the utilities have the -- sorry -- I'm not sure that the Commission has the data to assess that question to benchmark performance today on a utility by utility basis or the Railbelt bulk energy system as a whole compared with, say, cooperative systems outside.

I would also say in terms of results there's a -- and we'll come back to this later -- but there's an important question to ask about who should best determine the level of reliability of the electricity systems as a whole. There's tremendous gravity towards allowing the utilities to make that determination. Because, after all, these are member owned or municipally owned utilities. And so there is some patina that consumers are able to make their reliability

preferences somehow known and effectuated through those governance and management structures.

I think if you think about it even for a little while, that's at least an open question. It's unclear to me how I as a consumer would indicate my preferences unless I, like, got really pissed off. So, I mean, it takes -- most of us are pretty busy. It takes a lot to want to complain to anybody.

We talked about process, which is part of reliability. Right now it's voluntary. It lacks teeth among the adherents. So among certain participants we have, you know, mandatory agreements, and yet that mandatory thing lacks teeth. So we have seen recently, and you've seen in front of you, filings where reliability process standards have been violated. There's no consequence for that. That's maybe just fine. It may be just fine.

It may well be the case that costs of doing anything else are greater than the benefits, but I think it's worthy thinking hard about how you'd actually evaluate that question. I'm not sure that I would simply rely -- I don't -- I'm not sure that it is appropriate, actually, to simply

rely on what the deep expertise of the utilities have in running these systems in terms of their assessments about what's appropriately reliable.

Because, after all, at the end of the day, we're dealing with a non-billed value. Consumers can't walk. They can't address this with their feet. And then, again, we've got this fact, which is that we organize our economies and our lifestyles around the level of reliability that we have. And so preferences for reliability are indigenous, that is affected and caused by the existing level of reliability.

And, lastly, of course, we talked about the transmission system lacks a good business model to ensure future reliability. So you've seen this before. You can have multiple efficient answers. Answers can be locally efficient, not necessarily globally efficient. Two answers might be both similarly globally efficient.

For example, suppose it's the case that new transmission was built. It liberated opportunities for economic dispatch, and it was a wash in terms of costs to the ratepayers. From a perspective of cost, if you're looking for optimal cost structures, you've got two hills. They're

both at the same height. They've got different mixes of inputs to get to that same height, but they're nevertheless different, right?

One might be more reliable than another. One might offer more resilience than another. So whenever we think about these problems, it's important to think about the extra dimensions that aren't being captured by the stories that are being told about why this system is good or bad or indifferent.

So let's talk about effective and efficient. Because, again, your charge deals with effectiveness as well as efficiency. I'd suggest that one of the measures for an effective Railbelt transmission system is that there's a good business case for building new transmission when it's needed. And, indeed, in advance of when it's really needed. I don't think you have that. I don't think you have that.

And we talked about that. And others have made filings here in front of the Commission. I think it is indicative that -- or that's the wrong word. I think it's interesting that there have been efforts to go to the Legislature to ask for funding for various transmission improvements that

would provide larger benefits.

Is there a process for determining and enacting appropriate system-wide upgrades? A process, right? Like an IRP process. We had the Railbelt IRP sponsored by AEA. But AEA's got no authority to do anything about it. So we can get another State-sponsored study, and it's just informational. Can't -- so you've got -- we do not currently have institutions that can promote region-wide planning. I would suggest that that's not effective.

Do the utilities have ready access to the capital they need to provide affordable, reliable service? Well, mostly, but not always. In fact, it's -- if you go through the orders and issues in front of this Commission, there have been periodic times when there was not adequate capital to do the things that people believed were needed. And, again, I would just point out that at least within the last year I've sat in the back in public meetings and have listened to utility management explain to you that they're tapped out. They lack sufficient capital. They need help from the State.

I would submit I don't think that's -- no.

From my perspective, that's not evidence of a particularly effective institution or set of institutions. Do each of the utilities have the breadth and depth of expertise that would be helpful? To some degree absolutely. But I've also heard among utilities there's recognition -- like, some utilities have a lot more people around to do the various things that might be done to do the analysis that might be helpful. And some of the utilities are outgunned, outmanned. They don't have the resources to critically assess, well, is this a good idea for us or not? They're busy doing other stuff.

In general, in the utility sector, what we -- I mean, it's widely appreciated we've got a graying work force. We've got a whole lot of institutional capital which is walking out the door, has walked out the door, getting ready to walk out the door. Having multiple atomistic entities spreads things thin. It is harder to foster resilience in human capital and transferred institutional learning.

Do I think each of the utilities are working very hard on this? Absolutely they are. The question is whether structurally we've got the

best, most effective institutions for helping foster that process. Again, we -- we've -- going back -- going back to slide 9, we've got an optimum. Each of the utilities are doing the best they can. Given the institutions available, they're doing a good job. But that doesn't mean that there aren't other institutions that would have other salutary effects that might be preferable.

Okay. Back on slide 10. Well, we've already talked about that, foster replacement and cultivation of institutional knowledge.

CHAIRMAN PICKETT: Antony, I think this may be a good break point for a few minutes, and go back to slide 10. We'll leave the red lines up and we'll see if Commissioners have any questions on that when we come back.

DR. SCOTT: Very good. Thank you.

CHAIRMAN PICKETT: So we will be off record for about ten minutes.

(Off record.)

CHAIRMAN PICKETT: We are back on the record. It's approximately 10:10 a.m. And at this point I will turn to any of the Commissioners. Any comments or questions for

Antony before we move on to slide 11?

Okay. Well, you got off the hook on the red line page. So move on.

DR. SCOTT: Thanks very much.

On to slide 11. So I think there are reasons to believe that from a global perspective, a regional perspective the Railbelt electricity provisioning system is not -- again, measured in cost -- as efficient and effective as it might be. That's not the result of intentions. And it's not the result of incentives.

You know, electricity systems need to deliver instantaneously on demand. Systems doesn't -- they don't work unless demand is met at every instant and every place. What does that mean? That means you need a lot of supply in order to ensure deliverability. That means you're going to need excess capacity. And you have to operate within constraints, and there are many operational constraints. We talked about that last time. A lot of operational constraints.

But here's the thing. It's just a -- it's a function of math. Okay. It's just math. This is a theorem that any complicated system -- any complex system will operate more efficiently if

you have fewer constraints. And it's also the case -- I mean, this is -- again, this is straight college math. Any time you have a constrained optimization problem, you're going to -- it's going to be suboptimal compared to the unconstrained optimization problem.

It's also the case that inter-utility coordination allows for relieving some of the constraints associated with providing electricity instantaneously and reliability at all times in terms of reserves, spinning, capacity, regulation, human capital, hydro resources, transmission cost recovery responsibility. A whole other -- a host of other things. If you have adequate, functional coordination, you can relieve the constraints to some degree globally because you don't need as much excess.

If Erin's utility has to regulate her own power system, the resources required for her to do that separately from me regulating my own power system are going to be greater than if we pool the regulatory -- the power regulation needs between us.

CHAIRMAN PICKETT: Question for you: In your last bullet there on "other," just

my own theorem about the weakest link as it relates to complex systems, would you put that in sort of that other category?

And what I mean by that is there can be long-term contractual agreements, relationships, all of that kind of stuff that play a pretty critical role. But something happens and something breaks down. And the impact on the overall system can be significant.

DR. SCOTT: Absolutely. I -- I mean, here's how I'm interpreting or hearing or understanding your question. And that has to do with the flexibility -- the ability of your existing institutions to respond to perturbations. Whether those are commercial or physical or human. And, in general, if we are more atomistic and balkanized, the resiliency of the system, its ability to respond to those perturbations will be reduced, right? But I'm not sure I've correctly interpreted what you were saying.

CHAIRMAN PICKETT: Close enough. Continue.

DR. SCOTT: So there's some necessary functions, right, that have to get performed. And here's a long list of them. I

don't need to read through them in the interest of time. You know this stuff better than I do. But these are all functions of the existing institutions. The existing institutions do more or less well. And if you were to recommend movement towards a new set of institutions that sought to increase inter-utility coordination in some fashion to relax some of the constraints and thereby improve the efficiency of the system as a whole, the new institutions would need to take on all of these necessary functions. These necessary functions would need to be divided up, allocated among the new institutions, whatever they are.

So let's talk about institutions. So I'm going to give you the Scott version of definitions. And this is just for the conversation here. Other people will use these terms more or less similarly. The important thing is not laying claim to the particular meaning of a word, but that we can reasonably understand each other, I think.

So what's a TRANSCO? As I'm using that word -- and this is, again, reasonably widely shared -- it's an entity that owns and/or operates transmission assets. The operation of those

transmission assets or the ownership of those transmission assets will be separate from the interests of generating entities.

So a TRANSCO is a company which holds and/or operates transmission assets. And they do so separately with separate interests from the generation functions. So, again, other people have different particular nuances on these concepts, but this is what I mean to indicate, right.

Dispatch entities: We've talked now for some weeks about different types of dispatch entities. When I used the word ISO and I had a little strike through in previous presentations -- like, ISO, I don't think that's a viable policy option for you to recommend -- it's not that an ISO -- we don't want an ISO to perform various functions that are enumerated here on slide 13. It's that there are a couple of functions that are peculiar to ISO's in the Lower 48.

"I" in ISO is independent. And independent of what? Independent of generator interests. ISO's oversee -- and this is the critical thing about ISO's, as I see them in the Lower 48 -- is they oversee the competitive wholesale electricity

markets. And they do that by a requirement by the FERC that they are structurally independent from generating companies.

The reason why I don't think ISO is a viable option is because in an ISO framework, prices that are ultimately charged to consumers are formed on the basis of market outcomes, that is supply and demand. Both long term and short term, but supply and demand. It's just contractual. The regulator -- folks like you -- do not get into the business of determining what costs are.

ISO's have a critical role to play in market monitoring and in ensuring that market outcomes hew closely to cost-based outcomes. If market outcomes are generating prices that are ultimately paid by consumers that are substantially in excess of the cost of providing that service, that's an indication, right, that you have a market which is not structurally competitive. Doesn't have enough buyers and sellers, or it's got buyers that are able to exercise market power because of their particularly large market share.

In general, the experiment of wholesale competitive markets appears to be working very well. The market monitoring functions and reports

that get generated seem to indicate that in the Lower 48 wholesale electricity prices are very close to the minimum cost of providing service. How is that assessed? Through realtime modeling. That realtime modeling function where you compare market outcomes against the least cost dispatch on a cost basis would be something I believe that would be important to do should you propose an experiment in loose pools. Because, after all, in a loose pool you would be leaving a lot of the gains from trade up to voluntary actions of the parties.

And I'm jumping down, now, to this bottom sub bullet. In a loose pool, utility responsibility for control area services is retained. There's reserve sharing. There's coordinated but not centralized dispatch. So you don't have one entity that makes merit-order decisions about what gets dispatched. Instead, each of the separate utilities would retain substantial authority over their own -- the operation of their own plants.

And that's fine to go down that path, but it raises, I think, an important question which is -- okay, I mean, the claim is, look, let's just do a loose pool. We'll avoid some of the costs

associated with managing a tight pool. That will be good. And we're going to get -- we're going to wring out all of the benefits that could be wrung. Because we're not stupid, and we have our customers' best interests in mind.

Both of those things are true. These utilities do have their customers' best interests in mind and they are far from stupid. They know what they're doing. Nevertheless, for reasons we've already discussed, it is not always the case that loose pool coordination necessarily is going to result in wringing out all of the benefits. I think it's a testable hypothesis. Why not test it?

If you're going to go down this route, I would encourage imposition of ongoing realtime market monitoring to assess on a regular and transparent basis so everybody can see, how close are you? And if it looks like there are benefits that could be obtained by organizing differently, then you've got another bite at the apple. A tight pool -- the concept of a tight pool would pry a lot of operational control from the atomistic operation of the utilities, and instead centralize it within a single authority and then

would do merit-order dispatch on the basis of cost.

So as I'm using these phrases, that's what I mean. In an ISO costs are determined on the basis of market transactions -- sorry -- prices to consumers are determined on the basis of market transactions. The market transactions are -- well, that's what is critical about an ISO is they oversee the functioning of those markets.

I think it's unlikely that you're going to recommend we go down that path. I haven't heard anybody suggest that that's a particularly good idea for us to do now. So there's no question, really, whether you're going to have centralized dispatch of generating assets or whether you're going to have augmented coordination in some way and a platform for increasing the transparency and reducing the friction for -- of trades among the entities. Maybe with preexisting tariffs that split savings, what have you.

So on slide 15 I'm just saying, look, there are a couple of ways -- if you think about a TRANSCO, which is going to own and/or operate transmission facilities and some kind of dispatch entity that is making use of those transmission

assets, right, there obviously needs to be extremely tight and realtime coordination between those two entities. And there are different ways that this can get handled. You can have one institution that basically houses both, or you can have your dispatch entity that is maintaining operational control of the transmission assets, substantially.

So, again, going back to slide 13, you've got some necessary functions, right, that need to be divvied up. And there are multiple ways of dividing up these functions among the entities. There are other institutional arrangements as well. So each of the previous types of institutions provide an initial -- their formation would provide an initial step on the path towards a more integrated Railbelt planning and construction, right?

We were talking before about dispatch. But in terms of planning and construction, there's a heck of a lot of dollars there. And there's some real opportunities for the system as a whole that might be gained from the perspective of assessing reliability needs and enforcing reliability standards, capturing economies of scale and scope,

improved ability to incorporate independent power producers or renewable energy, potentially reduce litigation among the parties.

So why hasn't it happened yet? We've been talking about it for a long time. I mean, not just this spring, but we've been talking about it for a long time as Alaskans. It's a deep question. And I have a -- I have my own views about it, which I'm about to share. We have multiple actors in this system with different levels of authority and expertise. Utility management actually understands what the heck is going on. These are the people with deep understanding and expertise in the system.

They're a portion of the system, larger pieces of the system -- globally, these are the people who actually know. And, as you well understand, your ability to learn about the system is a function of whatever it is that they choose to file with you. And they will always, assuming they're rational economic actors, shape what they file with you to best serve their interests. And you know that. And we have balkanized, separate, atomistic interests.

Which means, unfortunately, nobody's

providing you the tablets from Moses. You don't get the unvarnished truth. And, unfortunately, although it's been, again, as I said, a tremendously great learning experience, I'm not qualified. I can't help you out. I don't have the relevant expertise that you need. I don't think the Legislature does either. In general, I don't think the boards of these utilities do either, as a general matter.

The boards, of course, are meant to be where local values can be expressed at some level. Because at least for the co-ops you've got elected boards. RCA, of course, has got a fair amount of regulatory expertise, but your authority to push the parties together is uncertain. You asked a series of questions of the utilities and they came back with a bit of a splatter of an answer -- or splattered answers.

And, clearly, you have uncertain policy mandate as well. The fact that this Commission has been historically put on very short sunset periodically has done real damage, I think, in terms of the Commission's ability to be innovative and to push the envelope in any way on a policy basis. Because the Legislature has wanted to be

able to yank those policy decisions back to themselves. And that's fine. But then the Legislature gets to own the results.

And there's a problem with that. Because the Legislature has less technical expertise than this Commission by a long shot. They don't even get to learn what you guys do day in and day out in terms of filings. And, as I just said, as you well understand, the filings that you receive are always shaped to support the interests of the parties. That's not wrong. That's just how the system is.

The State Legislature, of course, has a lot of authority. They get to make the laws, which determine not only your authority, but, ultimately, at the end of the day -- at the end of the day, they determine the rules and the opportunities that each of the separate utilities are afforded. Each of these utilities has a charter. That charter, at the end of the day, is subject to the determination of the State Legislature. It also was not given from God. It was given to them by -- at the end of day, by the Legislature, which means it can be changed.

Are there complications associated with that?

You bet. Historically the Legislature also had tremendous power in terms of being able to offer money to build infrastructure. And at some level in some cases potentially was looked to, hey, you know, help out. If you throw a bunch of money in that my ratepayers don't have to pay for, that's awesome for my ratepayers. And we can paper over some of the differences that we might have from one utility to the next.

Well, infusion of capital. Clearly, that power, at least going forward as most people seem to see it, is radically diminished compared to what it was just a few years ago. If that's right, at the end of the day, the cost responsibility for moving to any new system is going to reside, at the end of the day, with the ratepayers.

But, again, as I pointed out some weeks ago, most of the money was coming from Railbelt consumers anyway, just in a different way. It wasn't through their utility bills. It was associated with the money that could be allocated to Railbelt citizens through the capital and operating budgets. You spend it one way or the other.

So given these dynamics we've got the iron quadrangle of inertia. The iron quadrangle of inertia is incredibly powerful, particularly in this state. Let's face it, we collectively have a strong libertarian bent. Do not tell me what to do. Do not tell me what to do. It's a powerful metaphor. And, as applies to individuals, it is hard to argue with.

We are deeply suspicious as a people of coercive power. The Legislature is not particularly inclined to be so coercive with regard to the actions of any of its citizens. Personally, I like that. However -- or in addition, utilities aren't individuals. Utilities, at the end of the day, are companies that have charters that provide necessary goods and services. Who pays for them? The citizens.

Unless you believe that citizens as individuals are fully and adequately making their desires known through utility management, if you believe that instead there are real opportunities from a governance perspective of some slippage between the desire of consumers -- who, again, at the end of the day, pay for this infrastructure -- and the decisions that are made by management,

then it calls into question whether forbearing from the use of coercive power best meets the needs of citizens individually and indeed collectively in terms of the economic opportunities that we have. Because, after all, these are critical infrastructures.

So I have several slides -- I'm on slide 19 now. I have several slides with the heading, policy innovation, coercion, and negotiation. I think this is the crux of the issue for you all. In deciding to do anything other than a continuation of the current approach, you would be recommending that the organization of these entities not be fully left to their own devices.

That means you would be recommending the exercise of some degree of coercion. Again, that's not a comfortable fit with who we are as a people. This is a non-billed value. It's an important non-billed value. But I think it deserves critical assessment in terms of whether the metaphor of not wanting a system in which entities are coerced to do things -- that is made to do things other than what they would all on their own -- carries over from the metaphor of how we handle individuals and then how we handle the

management and operation of companies that provide this critical infrastructure for us.

So I've talked a number of times about the importance of market failures, right? Because market failures, you don't have any competition, they're unbilled goods, free rider problems. Market failures call into question whether the current governance of the utilities fully reflects what consumers ultimately desire.

Look, if I don't like the T-shirts that JCPenny's offers, I can go elsewhere. I don't have that opportunity to do that with my electricity service. If I don't like the bananas at Fred Meyer's, I can go to Safeway. I don't have that opportunity with electricity service. Why? Because these are monopolies. Why? They're natural monopolies. This is a function of the technology. And then, meanwhile, there are a whole bunch of unbilled values that don't even show up, right, that I might have.

What that's saying is that the information that consumers can readily provide to the providers of service is much diminished in this business. And that's why we have regulation. It's why we have policy. So who should determine

the right level of response -- of reliability? Well, right now, substantially, practically, the right level of reliability is determined by the management in each of the separate utilities. And that's fine. I mean, it is what it is.

Do utility engineers know the level of reliability of the system as a whole that their consumers, their customers most demand? Well, maybe they do. But I think it deserves asking: How would they know that? Well, they're member owners. Okay. Fine. It still begs the question: How would you know that?

The provision of information from consumers to the producers is being squeezed through an exceptionally narrow straw compared to normal market outcomes. You guys have statutory authority around reliability within and possibly across. There's some dispute about that among the regulated utilities. Possibly across the service territories. So you have it. I would suggest that given that that's what the Legislature gave to you, it's fully within your ambit to drive on that one as hard as you want and ask some really hard questions about what kind, how robust and redundant a system is appropriate?

These are policy calls that have to be made. Somebody gets to make them. Who's the right level of authority making them? Again, deep distrust of regulators, of government, of coercion in this state. We all do. But I would also say, good, better, or indifferent you all have pretty clearly at least within the utility level have been given the statutory authority to oversee this.

So on slide 21, if -- if the utilities are not able to self-organize to capture all of the efficiency and effectiveness that might be captured -- and I think as an outsider, the evidence that I've seen looking at historic orders, looking at past studies supports this view, that is self-organizing entities -- I mean, look, we are -- we have devolution of coordination right now.

We have five control areas instead of three. This does not look like an increase in self-organization and an increase in cooperation to me. There are good reasons for that, and it doesn't -- but, anyway.

So if you're not going to leave the establishment of a more efficient and effective Railbelt system to the utilities, then what? I

see really kind of three paths. One could, if one were sufficiently smart, make a very detailed recommendation to the Legislature. Very detailed, saying here's what you should design, right? And go design the watch. We talked about this metaphor before, right? Go design the watch. I utterly lack the capacity to help you with this. I'm not smart enough. I don't know enough. And even if I did, I'd get it wrong.

I actually don't believe, personally, that overly prescriptive statutory framework is the right answer here. And that has to do with the fact that I don't think it can be -- the process of creating legislation can be adequately leavened with information for a system as complicated and difficult as this with as many competing voices and interests.

So should it be just left up to the RCA? That is, do you currently have the sufficient statutory authority and tools to make this happen all on your own without the Legislature doing anything? Well, I believe probably you could do some things. We'll come back to that in a minute. I think in general everybody -- well, I don't know if everybody.

If it is appropriate for the formation of some new set of institutions -- which really needs to be thought of as starting a path rather than designing a final result -- it's probably the case that the Legislature should provide RCA with some new clarified powers, and then allow the RCA to guide the process as a backstop encouraging the voluntary coordination and cooperation among the entities. I'll explain what I mean about that in a minute.

So the first -- the first big issue, of course, is if you're going to design any new institutions that are encouraging greater degrees of coordination and cooperation, you're going to have to exercise some coercion, I think. Some additional authorities could probably be helpful. And -- and what would they be? Well, I'll talk about the proactive one in just a little bit.

I think some enhanced standards around the concept of prudent utility practice and management that possibly extends to inter-utility practice and management might be helpful. If the problem is that acting individually utility management is not able to capture efficiencies or effectiveness, if that's the problem, then the only way to

address that is to think -- to broaden the scope of how management understands their role to include the function of working together. If prudent utility practice is not just about running my own company as efficiently as possible but also entails adequate cooperations that globally between the two of us we can run our utilities as efficiently as possible, that might be a useful tool.

Entirely as a backstop. Entirely as a backstop. But right now, right, you have authorities around prudent utility practice. And, indeed, in the limit, you can decertify utilities for not exhibiting prudent utility practices. Hasn't been done. Hopefully, would never be done. But in the limit, you have that. You don't have anything like that right now in terms of putting on the radar for utility management that part of their job is not just to manage their own assets for their own customers.

So how would you use that kind of coercive power if you had it? Ideally never. Probably never. So this has been sort of initially the FERC's approach to creating RTO's, right? Basically said, it's voluntary; but if you don't,

come back to us and explain why you didn't. And, interestingly, people came back to them with RTO's. And that's the best kind of result. Because the parties with the expertise were able to talk to each other who also have expertise and negotiate appropriate solutions for their particular circumstances.

I mean, the issue of information and expertise is profound. If you have people making decisions who don't really have it, you can be sure they're going to miss the mark. It's like driving while blindfolded. It ain't a good thing.

So ideally in terms of any new coercive authorities, it's not that you ever actually exercise them. It's that you have them. And then in having them you can help guide in a structured, negotiated, facilitated process through workshops and other more -- less informal, more confidential means and encourage the parties to come to resolution and agreement among themselves. That's how it should happen.

But if you don't have any coercive authority as a backstop, it's pretty hard to make any of that happen. Because it's like, yeah, yeah, whatever. Listen, I got things to do, right? But

if part of your thing to do has been articulated by the Legislature as, no, no, you're expected to consider -- when you're managing what you do, you are expected to wring out the efficiencies that might be wrung out through greater levels of coordination with your neighbors. That might be helpful.

So the next series of slides is -- I'm on slide 23 now -- is really just meant to address some complicating issues that have to get addressed in any transition to anything new. These are all complicated. I don't adequately understand them. Probably not very many people adequately understand them all. And that's because, in part, they involve utility-specific information and values.

But the point of just going through these next couple slides is to indicate the practical difficulties and barriers associated with trying to get too prescriptive at the Legislative level. And I'm really speaking right now to the Legislature. We do from my perspective -- well, there is reason to believe that there are -- from one set of perspectives there are problems with the way we are currently organized.

Given a different set of perspectives, there aren't. We are in the best of all possible worlds because the unbilled values around independence and lack of coercion and so on are really important, and that's what we want. And we're doing well enough with the other stuff and it's not worth the trade-off. And at the end of the day, that's not for me to opine on. I have my own views about what I care about, but that doesn't matter.

But if the conclusion of policymakers is that, no, we should think about new institutions to foster other kinds of efficiency and effectiveness, then there are a whole bunch of complicated issues that need to be worked out. And it's -- trying to design the watch at the legislative level is probably not the way to go. And that's really the only purpose is just to indicate a small subset of the things that need to get worked through.

One of the things that needs to be addressed is if some entities really, really do not want to play, is there space to carve them off so that they don't have to? Is there a way institutionally, economically, technically,

practically, to say, look, you really don't want to play in this game and your customers are really fine with that? Okay.

There may be opportunities for carving entities off that do not want to play. Those opportunities will be highly fact specific, technical, economic, political. Not something that's easily handled at the legislative level, but may be handled by this Commission. Ideally, through a negotiating process of some sort. But if need be, through fully articulated orders.

There are complications around how best to handle AEA-owned assets in any reformulated system. These are not show stoppers, probably, but they need to be addressed. There are complications around RCA's lack of jurisdiction over the Bradley Lake agreements and how those agreements interface and function with the authorities that you do have.

Some legislative initiative with regard to this set of questions might at the end of the day be extremely helpful. I don't know the issues well enough to even begin to think through what the answer is. But it is fact specific and complicated.

Asset transfers or sales: You know, these are complications, certainly, say, in the formation of a TRANSCO. For one model formation of a TRANSCO would have transmission assets. The actual ownership of those assets transferred to a new entity, there's some complications around that in terms of co-op voting rights. It may not be necessary at all for TRANSCO formation, although it may be helpful for some of the utilities' balance sheets to get an injection of equity.

How to manage both of those things is one of the things that needs to be worked through. Ideally, the parties themselves would do that. Who pays for new transmission assets, right? You can have full social -- full socialization, postage stamp rate entirely, or you got issues around, well, no, if it's our radio line connecting a generator then they have to fully pay for it. But what happens if actually there's shared benefits between both the generator and the transmission system as a whole? Now you're getting into issues that you've had in front of this Commission recently around how to allocate costs and benefits.

Clarifying rules around this set of issues

going forward would be extremely helpful. Ideally, you'd have an R docket of some sort to clarify how this is going to work so that it's -- everybody understands on a going-forward basis. And then you don't have to fight about it anymore.

You have complicated issues around competitive entrance, independent power producers. How do you fold competitive entrance into these new sets of institutions? Good set of questions. Complicated, very complicated. At some level probably some legislative innovation needs to happen around this. But I would, again, underscore, you can't just replicate what was done outside. Because there is no reason to believe that determining prices for consumers on the basis of market transactions between buyers and sellers is going to result in least cost power going to consumers.

Structurally we don't have enough liquidity up here. And it's not just between buyers and sellers of electricity. Structurally we don't have nearly enough liquidity in the hydrocarbon markets. We don't have enough buyers and sellers of natural gas or of coal to help effectuate fully competitive wholesale markets. That actually

raises some complications for thinking about how to inject IPP's into the Railbelt.

I'm not saying it shouldn't be done. I actually have great fondness for competitive entrance, but there are some complications around how that would work. That would have to be worked through, and this Commission is the place where a lot of those details need to get worked. Some legislative tweaks, probably. I mean, there's -- there's a funny thing that, in general, independent power producers, for the most part, need to get certificated as public utilities under our statutes.

That's totally different from what you see outside. It does not fit the model, really, for bi-lateral deals between willing utility purchasers and competitive entrance. Because as soon as you're certificated, then it raises the question of, well, should you then regulate the cost of that power provision on a cost of service basis? You know, obviously, that's not what's happened to date. But if you're not regulating on a cost of service basis some public utilities but you are regulating on a cost of service basis other utilities, there's some messiness down the

road that you can foresee happening.

There are a whole bunch of ratemaking complications, obviously, that will end up in front of this Commission in terms of transmission rates. If you wanted to have a postage stamp rate as the ideal answer, which would indeed facilitate the greatest level of economic dispatch, you would need, I would think, some transitioning toward such a rate structure so that you don't have rate shock on the side of customers.

And also to provide utilities, which would be gradually shouldering increased transmission costs, the opportunity to take advantage of -- well, to take advantage of new opportunities for enhanced power sales, which hopefully would offset fully -- more than fully any increase in the transmission costs.

So in a transition I've suggested that the RCA's got an important role, critical role to play. I think you're closest to the formation of any coercive entity. But casual observation suggests that you are not resourced now to manage such an effort. I'm astonished at how thinly stretched you all are. If any of the people behind me have ever had an opportunity to go

upstairs and go into any of the offices of the Commissioners, you'd be astonished at the amount of paper which is in stacks more or less well organized. I'm glad you can't come into my office. It's unbelievable. I wouldn't want your job.

The Commissioners don't have time right now. They are very thinly stretched. And there's not adequate staff. And it's not just numbers, it's expertise. That the Commission needed to hire me is indication that they don't have enough expertise. They're too thinly stretched. People are busy.

You also need resources from mediators. Because, again, as I suggested, the only way this ultimately works is through negotiated outcomes, probably backed by some coercive authorities that hopefully are never exercised. But you seed some very skilled mediators who are capable of not being swayed or influenced by the deep preexisting multi-decade history among the parties in terms of trust or lack thereof.

I mean, if anybody has been in a bad marriage or in a marriage that has gone bad or any other relationship that has gone bad, one of the things

that happens is you stop hearing each other because you already know what the other person says, means, intends. And for us to move forward to create anything new will require that the parties hear each other in novel ways. And that is exceptionally difficult given multiple decades of often very contentious history. And the only way I see forward is to have some very skilled mediators who are capable of getting outside of those communication difficulties and helping foster new understandings to capture more opportunities.

And all of this is going to take money. So I'm not going to make very many recommendations. I haven't made very many recommendations. But if the Legislature would like to see something happen, my recommendation is -- the first recommendation is they need to empower the RCA to get enhanced resources through the RCC. Because I just don't think it's practical for you to do very much given how you're currently resourced. It's a necessary enabling condition, I believe.

This doesn't require legislative appropriation of operating budget. It needs -- it's about budgeting authority for this agency

through the RCC. Would ratepayers pay for that? Yes, they would. Is the overall burden modest? Yeah. It would be. This is not even remotely an exhaustive list, but in terms of a couple of big buckets of issues -- I think that the first big bucket of issues in terms of legislative effort in a very general way would be to clarify that the Commission's authority, its jurisdiction extends not just within a CPCN but across CPCN's.

Again, there is some disagreement among the entities that you regulate around this question. At the end of the day, you could go forward without this clarification. However, you might end up in court. In fact, I just about guarantee you'd end up in court. It would be nice to substantially bypass that step. I think potentially one of the authorities that should be clarified in terms of your jurisdiction across CPCN's has to do with the concept of prudent utility practice. That would help effectuate increased economic dispatch and provide some reach towards transmission planning, perhaps. Perhaps.

Creatively used, I think it probably could. What I'm suggesting here is it doesn't need to be a complicated, heavily worked bill with lots of

details. Some modest clarification of expanded RCA authority would be helpful. Now, let's recognize, this is not a popular thing to say or to do. You're talking about giving regulators increased coercive power. I mean, how bad does that sound? It sounds bad, right. Does to me.

Absent relying on the parties to self-organize -- and we've heard many times over the years the parties explain that they are self-organizing and they're going to get there and we're working it out. I mean, I, personally, as an outsider reading orders, reading studies, I feel like Charlie Brown and Lucy.

It's the wrong metaphor because I don't believe the parties are snatching the ball away. I don't think they're putting it down just to trick us. I don't think that's true. I really don't. But rather than Lucy snatching the ball away, the ball gets fumbled somewhere along the way, and I end up on my back or we do collectively.

Again, from the perspective -- and it's a narrow one -- of thinking about economic efficiency and effectiveness as measured on bills, there are good -- again, I mean, I need to stress

there are reasonable and good reasons for deciding, you know what? We don't want to be organized like this. We're going to leave it up to industry to look out for their consumers. They have the expertise, and we're done with it.

But then, Lord help us. Let's not do any more studies. Let's not look at this question anymore. Let's not talk about it anymore. Seriously, I mean, let's just stop it, because it is infuriating. It's been going on for many decades. It's boring. There are other things to do. I think it might be helpful if the Legislature clarified that the RCA's authority around reliability was inter-utility as well as just within a utility.

I actually -- my own read of the statute -- I'm not a lawyer. I don't know. But my own read of the statute is you got this. You have that authority. But, again, the attorney general, who is sitting to my left, could speak for this question in private probably. But it would probably be helpful. Avoid a trip to the courthouse, possibly.

I actually think the issue of siting authority could be helpful. What do I mean by

siting authority? I'm not talking about where you locate a specific power plant. I'm talking about whether -- I said "what" here, that's -- I'm on slide 27. That's not the right word. It's really "whether." It's whether utilities need to come in and get permission before they construct. If you had the authority to say, no, you need permission before you get to construct, one read on that is oh, well, now you've got the Regulatory Commission. It's nanny state stuff, right? They're telling you what you can and can't do.

But another slightly more charitable view of this is it would be a backstop tool which would allow you to ensure that generation additions were made on a regional basis, that is to say joint planning occurred. How would that work out? Well, you could say, you don't get to build any new generation assets unless they are consistent with an integrated resource plan. And the integrated resource plan's scope is regional. And that would provide a public forum and provide an opportunity again for essentially soft coercion.

Look, this is the framework around which you add stuff. We're not going to design a power plant. You guys are going to do that. But the

expectation is that whatever it is you choose to build is done jointly. And that joint public airing of needs and expectations and technical assessments could help ensure that when it was time to build something new, the most efficiency that could be wrung from that new investment was wrung.

I think that would be a good thing for Railbelt consumers, personally. I think the issue of siting authority would be particularly important. Were it to come to pass that there were a transmission company that is a TRANSCO that owned transmission assets, especially in a world in which that TRANSCO was an investor-owned utility -- which we do not have right now in the Railbelt. But if we had an investor-owned utility that was a TRANSCO, siting authority would be an important check to ensure that you didn't have goldplating. Because investor-owned utilities have an interest in investing. That's how they make their money; more investment, more profits.

And so it would be a reasonable thing to require a public process so that the generating interests, the consuming interests could have an opportunity to be heard to say, you know what? We

don't need that transmission line this guy wants to build. We don't need it personally, and we don't think that Railbelt needs it globally. And those sorts of checks in terms of processes I think are probably pretty helpful.

These are the only two buckets that I have in terms of authorities. I think you could go a long way in terms of institutional innovation before you needed to go back and get some more. There are for sure some complications around the Bradley Lake agreements that are going to have to get dealt with, and that would have to get dealt with in more robust global regional kind of set of institutions and infrastructures. Because, again, it's outside of your regulatory ambit.

But it might well turn out that the resolution of those issues doesn't need to get solved up front first. How those agreements needed to be resolved, if they need to be resolved, my hunch is that that would become clearer over time in an evolutionary way. I could be totally wrong, but this is my sense, and maybe that's just because I'm so ignorant.

There's so much that I'm aware of not knowing about how all of the details fit together. I

think taking a gradual approach is important. It allows you to elicit more information and more information. Ideally, most of the information that's elicited is from the parties and directed between the parties themselves with, again, at the end of the day a coercive backstop. Guys, figure it out or we will. And that would put the fear of God in me, I know.

Well, it would involve people as ignorant as me making decisions about a whole bunch of details that would be easy to get wrong. I mean, having enough information in the room is a hard thing. And communicating it to people who don't fully understand is very hard. I'm not suggesting you all are as ignorant as me. You're not. You're much better informed than I am. I mean, you've been at this for a long time if nothing else. I mean, I need to clarify that.

But the information asymmetries are real. Part of the problem, unfortunately, is I don't believe the entities speaking to each other hear each other very well. And that's a problem, because they need to work through this.

So slide 28. I think legislative endorsement would be helpful. Legislative endorsement for the

RCA to promote a more efficient and effective Railbelt system. I think the pledging of certain State assets to that effort, at the end of the day, making clear of that would be helpful. I don't think those are even remotely show stoppers. I think that will follow along as needed.

All I'm trying to do here is indicate areas where I think things would be helpful. People want to do stuff, this would be helpful. Necessary, no. Helpful, yes. Carrots to facilitate transmission construction, yeah, maybe. I'm not talking about appropriations. I'm talking about rate treatment.

Other places have done things around collecting interest during construction preoperation before assets are fully used and useful. We -- I've shared model results with you on the effectiveness of such measures in reducing the subsequent costs of those transmission revenue requirements. It could be helpful. And, certainly, any transmission entity would -- well, I think it's certain, would like that. I think it would be helpful. It would reduce their risks.

There is rolling around this concept of securitization legislation which would allow

on-billed charges for new construction. It's a similar kind of idea, but it would allow an opportunity for raising capital at relatively low interest because bondholders would know that they had, basically, a line item on everybody's bill that guaranteed recovery from ratepayers. And the line -- the size of the line item would be adjusted with overall demand, right?

So you would have ensured cost recovery. As long as you believe that there's a functional population and economy up here, you'd have ensured cost recovery. I think that's a pretty good bet. And, accordingly, the risk would be low so the cost of debt would be low. So might be helpful.

Slide 29, conclusions. I think the Legislature probably has some necessary roles. Increased RCA authority, resources are necessary. And some increased RCA authorities would be at minimum helpful. You might be able to get reasonably far down the road testing your authorities as they currently exist in statute, but some clarification would probably be helpful. Again, I don't think necessary, but probably helpful.

And I think the Legislature could provide RCA

with some ratemaking tools to incentivize the construction of new assets if that made sense. I think you probably have a necessary role to play in this. There are a whole series of rulemaking processes that you probably need to have to sort through a bunch of the issues. Some of which I've talked about and a bunch of which I haven't touched on at all.

And, ideally, you manage this process with some clear coercion as a backstop to help provide structure so that the nascent efforts that the utilities have made to voluntarily come together is contained and controlled and guided forward so that it can come to some fruition or some more fulsome fruition than it has to date.

And that is the end of my presentation today. And thank you very much for your time and attention.

CHAIRMAN PICKETT: I will now turn to the Commissioners for any comments, questions, requests for clarification that you may have at this point.

Commissioner Rokeberg, do you have anything?

COMMISSIONER ROKEBERG: Give me a minute.

CHAIRMAN PICKETT: Commissioner Patch?

COMMISSIONER PATCH: Thank you, Dr. Scott. I appreciate your efforts throughout this process. And with respect to siting authority -- that's with the "s" not the citation "c" -- I did have a discussion with Senator Egan some three years ago. You may conclude that either I was unpersuasive or it fell on deaf ears as you observed with your comments about what's heard and what's understood.

I would also like to thank you and recommend to those in attendance that the availability of additional resource would certainly be helpful to the Commission, and it would likely also be quite helpful for the parties who appear before us.

Enjoy your time away.

CHAIRMAN PICKETT: Commissioner McAlpine?

COMMISSIONER McALPINE: I would only observe that a lot of the discussion that's gone on over the past several weeks is discussion that went on in the '70s. And the notion that there's going to be cooperation among the utilities, I think, is -- looking back on it, it

was like trying to swim in the ozone.

If the Commission had had siting authority 30 years ago, I dare say that a lot of what has been built may not have been built. A lot of what was done would have been done much differently. The competition among the utilities for State dollars was fierce during the -- and the gentlemen in the back of the room know this. The competition for State dollars was a bloodletting exercise in the '80s. And what we have today is, unfortunately, a result of that.

And I think that being the new guy on the block but with some institutional memory about what went on, siting authority is probably the single most important thing that this Commission could obtain.

CHAIRMAN PICKETT: Commissioner Wilson?

COMMISSIONER WILSON: So given where you're ending up, I just have some questions about governance. What are the relevant governance considerations considering your bottom-line recommendation here, which is -- doesn't recommend anything specific but says there are a couple of options?

So I just wondered if you would discuss governance in light of your bottom-line things that you've come down to.

DR. SCOTT: I'm going to try not to duck. That's a really good question. I'm more of a gradualist than some. I'm not nearly as much as others.

COMMISSIONER WILSON: Not nearly as much as me.

DR. SCOTT: I believe, as you've heard me suggest, that coercive power would be helpful in the formation of any new set of institutions. And I also believe that fully outlining all of the details of that is certainly beyond my ability to recommend. I don't see clearly how to get there.

And the reason why -- one of the reasons why I don't see clearly how to get there is because I believe if any proposal is adequately offensive at first blush, there are -- given how we as a Legislature and given how we as a State with strong libertarian values behave, I think that the risks of blocking forward progress in the policy sphere are profound. And so what that means is there is a dance of the possible and there's not

enough information for knowing what is possible right now.

Back to governance, what does that mean? If I'm a party which is suspicious of playing because I will lose things that matter to me for uncertain and risky gain, I need to feel reasonably comfortable that whatever the new structure is around giving up some degree of autonomy in terms of how I manage any assets, that I'm going to have enough voice in the process to have a reasonable shot at protecting my interest.

So the gradualist in me suggests that the ultimate governance structure needs to be substantially negotiated by the parties in a facilitated, structured way. Facilitated and structured by the Commission. I think you could articulate some principles around what governance organization might look like that need to be satisfied.

I think one of the important principles around any individual member's ability to protect their own interest is they've got either the ability to full on block -- I have veto rights -- and Erin referred to that before in her presentation -- or I've got at -- failing that --

because there are problems with that, right? That leads to gridlock in a hurry. And then where does that gridlock -- if the -- if it has to get resolved, it gets resolved through binding arbitration or maybe, heaven forbid, in front of this Commission. I say heaven forbid just because I don't think you really want the work.

So if that's not particularly attractive, then the next best thing might be -- to be reasonably confident in a governance structure -- so this would be a condition, like go back and come back with a governance structure which satisfies these conditions. You need to ensure that no small coalition will practically be able to determine the outcome. You need a reasonably large coalition to determine outcomes, right?

Then the concern that things will be dominated by a particular utility interest or that utility plus another guy would be assuaged. Then the number of seats and exactly the voting percentages and so on -- I think it might be very helpful to leave that to the members, that is to say the utilities today, to help devise what that looks like.

Now, again, that's an answer of someone who's

relatively conservative and a gradualist on this. You know, I -- there are -- obviously, you've received filings from other folks in this proceeding suggesting that, no, no. You need to indicate a board makeup which has got X number of seats and it would have a minority number of seats by the utilities. And you'd have to add enough sort of public seats so that the utility influence was adequately diluted. And, you know, I think that's reasonable. Texas did that.

What I don't know at all in terms of how they innovated is I don't have any insight at all into the -- what happened before. So there was legislation, but that was the result of stuff. And the stuff in terms of the negotiations formal or otherwise among the affected parties, I have no idea what that looked like. So, I mean, I just can't speak to that. But you can be sure there were discussions.

COMMISSIONER WILSON: Thank you.

CHAIRMAN PICKETT: Are there any follow-up? Commissioner Rokeberg?

COMMISSIONER ROKEBERG: Thank you, Mr. Chairman.

And thank you very much, Dr. Scott. It's

been a real great pleasure to be able to have an opportunity to work with you, to get to know you, and find you as wonky as I am among other people in these things, rather enjoysome.

I've certainly been following this for a number of years. And I particularly found it amusing and to the point when you said: We should either do this or stop talking about it. And I think that was a point well taken.

I do have a couple of issues I would like to get your feedback on now that we're in the wrap-up stage. One is I'd like to have your comments, given your self-described gradualism, is that is there anything you can recommend to us about how we could incrementally implement this type of activity?

And, particularly, when it comes to, for example, what I would describe as enforceable regional implementation of resource plan or IRP that we can implement, and how we could enforce it and pay for it if we didn't go to a full TRANSCO or a ISO?

DR. SCOTT: So in some ways the issue of joint regional planning is an easy one to bite off right now because we got a lot of

generation assets on the system. You know, the expectation is we're not going to need to add much more for quite a while. So since the stakes aren't really high about anybody particularly looking -- no, I think I want to build something big in five years. Maybe this is a good time for policy innovation, right? Because nobody's got any particular thing that they want to do right now. So in terms of -- this speaks to your concept of gradualism at least on the generation side, right?

How would it work in terms of a regional IRP? I think if you had siting authority with an "s" and not a "c," you could promulgate a rule which outlined a process to clarify that nobody gets to build anything, A, without first getting permission to ensure that the assets are appropriate to be paid for by ratepayers. But, B, that the assets that would be added are consistent with a regional integrated resource plan.

And who's responsible for coming up with an integrated regional plan? Collectively the Railbelt utilities would be responsible for that. And they would put on their views about what needed to be added, when, and where. And then you

would get to sort through it. And at the end of the day, you would say this is the regional IRP. This is what it is. And if you're going to add new generation assets, it needs to be consistent with this regional IRP. And then everybody would know.

COMMISSIONER ROKEBERG: And they could pay for it through their rate base?

DR. SCOTT: Well, the exercise of coming up with a regional IRP would be paid for, at the end of the day, through customer rates, absolutely.

But the separate atomistic regional -- I'm sorry -- the atomistic IRP's that the utilities currently do are paid for by ratepayers. I mean, they're doing planning now, they're just doing it atomistically.

COMMISSIONER ROKEBERG: And another thing that the Commission has discussed with you in the past, but could you just publicly state again how important having an independent and professional electrical reliability organization is?

DR. SCOTT: I don't know. I mean, honestly, I don't know. I think -- I think a

reasonable answer is, you know, the utilities are doing a pretty good job. Let's let them do a pretty good job. Ideally, right? I'm kind of wonky. At minimum, I think it would be helpful for the public as a whole and policymakers -- because I personally believe that there is an inherent policy economic -- because of economic development importance, I think there's an inherent policy role to play around the question of reliability.

I think we, collectively, need data to better understand how reliable we are and how reliable our processes are. I can certainly envision it being entirely possible that with better data and more transparency the management of that actually got left substantially to the collective wisdom of the utilities.

I do think that it's hard to -- I mean, having said that, I think it is -- well, it at least makes me uncomfortable. I don't know how to square the concept of mandatory reliability standards without consequences. So if my behavior affects your reliability, Commissioner, and I don't do something and so you suffer reliability consequences as a result, that's sort of calling

out -- crying out for agreed-upon mandatory standards that we both share to govern our conduct so that we don't have free rider problems.

And what one of the things that quickly follows on behind that, then, is some sort of enforcement mechanism. If the standards are mandatory, they're only mandatory if there are consequences for not following them. Otherwise they're just voluntary. They're voluntary and we really mean it, right? So this is a roundabout way of saying, I'm kind of a fan, personally, of mandatory standards that everybody has to adhere to. And I'm also a fan, at the end of the day, for some sort of teeth behind those standards but at minimum.

If that exercise of coercive power seems too expensive and that exercise of coercive power seems too inconsistent with who we are -- again, given my wonkish nature -- as backstop at a minimum I think we need much better and more transparent data collection and reporting so that we can assess the degree to which our system is reliable against external standards. Not just compared to how we were when things were really bad, but how we are now compared to other

jurisdictions outside.

Because, after all, we're at some level part of the same overall economy. And our economic opportunities are affected by how reliable our system is.

COMMISSIONER ROKEBERG: Thank you very much.

CHAIRMAN PICKETT: Well, I appreciate all of the presentations we've had since early to mid April on this, and then the last nine months of work with you, really, and the continued work we'll squeeze out of you when you get back from Africa here.

I, too, share reliability concerns. But I do get some comfort with the voluntary reliability standards, even though they appear to not have much teeth. And, you know, particularly with some cases in which things perhaps should have been enforced.

But having said that, I mean, the Commission does get involved with reliability. I think back to the 2007 Briggs Tap debacle involving a couple of the utilities. So the Commission on a very hurried schedule was pulled into that; ultimately, it got resolved. The power in Eagle River appears

to be reasonably reliable. So something was worked out. So we tend to get pulled into reliability issues whether we want to or not if the circumstances are sufficient.

So having said that, I will announce I received an e-mail from Mr. Trent at ML&P yesterday afternoon. And I will be putting that e-mail -- it deals with an MOU on centralized power pool and economic dispatch services. I'll put all the attachments into this I docket. And ML&P has agreed at our special meeting on June the 3rd to come in and make a presentation on that.

On that same meeting, I was contacted by Mr. Hickey at Chugach Electric regarding a consultant that will be in the state for about a week. Very knowledgeable about ERCOT. So we're going to take advantage of that and have a presentation from him. And I would encourage -- I've had a lot of sidebar conversations during breaks before the meetings start. And, you know, some would say I agree with this stuff or I don't understand that or I vigorously disagree.

I would encourage you, if you as a utility want to come in starting at the next public meeting which is next week and offer anything on

the record or file something into the docket, I more than welcome that. Because, quite frankly, if we don't get it into this record, it does not exist for purposes of the determination the Commission will make. So you'll have an opportunity next week on the 3rd and then on the 17th of June. And that will pretty much close down the door for we have a time line consideration here.

So having said that, Erin and Antony, thank you very much. And we will close out agenda item number 2.

Agenda item number 3, other business. Do any of the Commissioners have other business that needs to come before us this morning? Seeing none we'll close that agenda item.

Number 4, does the attorney general have need for an executive session?

MS. POKON: No.

CHAIRMAN PICKETT: We close agenda item number 4. Is there a motion to adjourn at approximately 11:48 a.m.?

COMMISSIONER PATCH: So moved.

CHAIRMAN PICKETT: Second?

COMMISSIONER WILSON: Second.

CHAIRMAN PICKETT: All those in favor say "aye."

(Collective aye.)

CHAIRMAN PICKETT: Thank you very much for being here this morning.

(Adjourned - 11:49 a.m.)

I-15-001
Alaska Railbelt Electricity System

USO Governance Structures and Issues

5/20/2015

ACEP
Alaska Center for Energy and Power

Legislative Charge

<u>RCA should recommend</u>:

Whether creating an independent system operator or similar structure for electric utilities in the Railbelt area is the best option for effective and efficient electrical transmission.

Getting to Economic Dispatch (redux)

- In principle can achieve more than one way
  - ~~One owner (e.g. REGA/GRETC concepts)~~
  - Tight pool/USO (1998 B&V, REGA, CH2M Hill)
  - ~~ISO~~
  - Loose pools
  - ~~Bi-lateral contracts (e.g. historical MEA-CEA, HEA-CEA, Bradley Lk CEA-GVEA dispatch agreements)~~
- Some institutions may fall short of ideal
  - Loose pools may fail to transmit information adequate to capture the full range of efficiencies
  - Bi-lateral contracts can create rigidities that stifle future trades

Strikeouts indicate non-viable policy *initiatives*; bi-laterals may be market viable

Two possible policy approaches towards economic dispatch

- Flexible market institutions (loose pool)
  - Pros:
    - Low transition and operation costs
    - Each utility maintains more control
    - Governance risks avoided
    - Not socialistic
  - Cons:
    - May not fully solve information and coordination problems
    - Some dispatch benefits will be 'left on the table'
    - No platform for efficient capacity additions

Two possible policy approaches towards economic dispatch

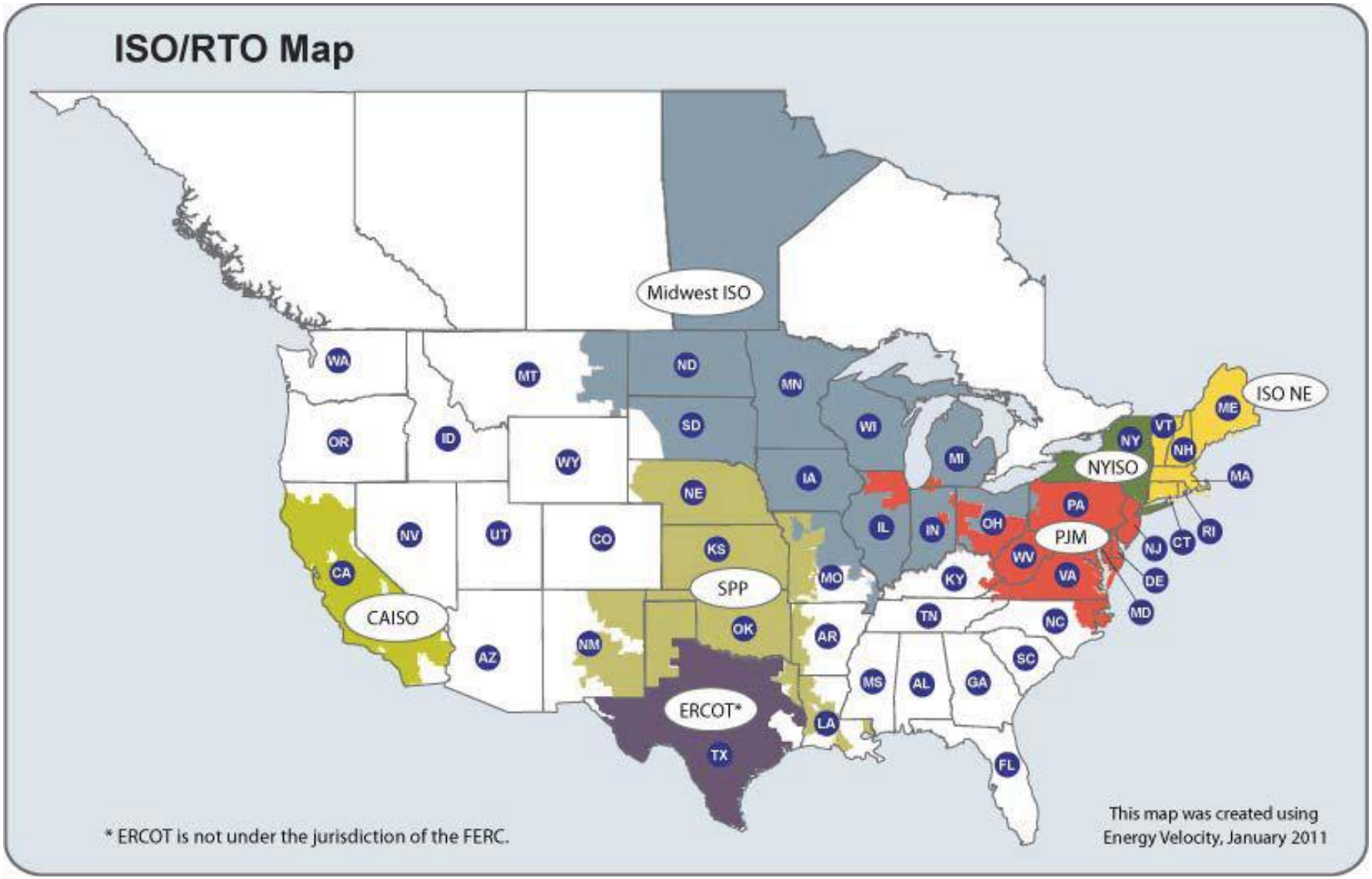
- "Central planning", e.g. "tight pool" or USO
  - Pros:
    - Solves information and coordination problems
    - Captures greatest degree of dispatch benefits
    - Platform for efficient capacity additions
  - Cons:
    - Transition and operation costs
    - Loss of control
    - Governance risks (distribution of benefits)
    - Ideological positions

"Tight pool"/USO Who decides? Governance issues

- Governance is about making key decisions
- How governance is resolved may affect
  - Distribution of benefits
  - Risk
- Governance determines the balance struck in taking away some control while providing utilities:
  - Buy in
  - Voice
  - Necessary conduit for technical expertise

Lessons from Outside ISO/RTOs

- Formed as a result of FERC Orders 888 & 889 (1996), and 2000 (1999)
- Issues generally revolve around independence of transmission operation from generator interests *to ensure robust, competitive wholesale electricity markets*
- An ISO/RTO is not appropriate for Alaska, but existing governance structures offer useful lessons.


ISO/RTO Map
Midwest ISO
ISO NE
NYISO
PJM
SPP
CAISO
ERCOT*
WA
OR
CA
ID
NV
MT
WY
UT
AZ
CO
NM
ND
SD
NE
KS
OK
TX
MN
IA
MO
AR
LA
WI
IL
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KY
TN
MS
AL
OH
WV
GA
FL
SC
NC
VA
PA
NY
VT
NH
ME
MA
RI
CT
NJ
DE
MD
* ERCOT is not under the jurisdiction of the FERC.
This map was created using
Energy Velocity, January 2011

ISO/RTOs typically perform several functions

- Market management
- Market monitoring
- Dispatch
- Transmission scheduling
- Operation of Open Access Transmission Tariff
- Planning
- Collecting revenue through charges for monopoly wire access, distributed to transmission owners, to compensate past and incentivize future investment

ISO/RTOs typically perform several functions

- ~~Market management~~
- ~~Market monitoring~~
- Dispatch
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Governance of ISO/RTOs: General Considerations

- Independence & Board Structure
  - Ensuring no self-dealing between Board decisions and affiliated parties
  - Composition, selection, termination, qualifications
- Stakeholder Participation in ISO/RTOs
  - Technical expertise and articulating interests
  - Advisory councils, voting rights, qualifications
- Division of authority between the two bodies

ISO-NE

10 person self-renewing Board

- Membership means no affiliated interest

NEPOOL Participants Committee

Advisory Committee

Appointed by Board

- Represents 210+ entities
- Advisory voting on ISO matters
- Endorsement of proposed nominees for the ISO Board
- Six voting "sectors" based on market roles
- *No legal authority over the board*
- *Reactionary rather than initiating role for stakeholders*

NYISO

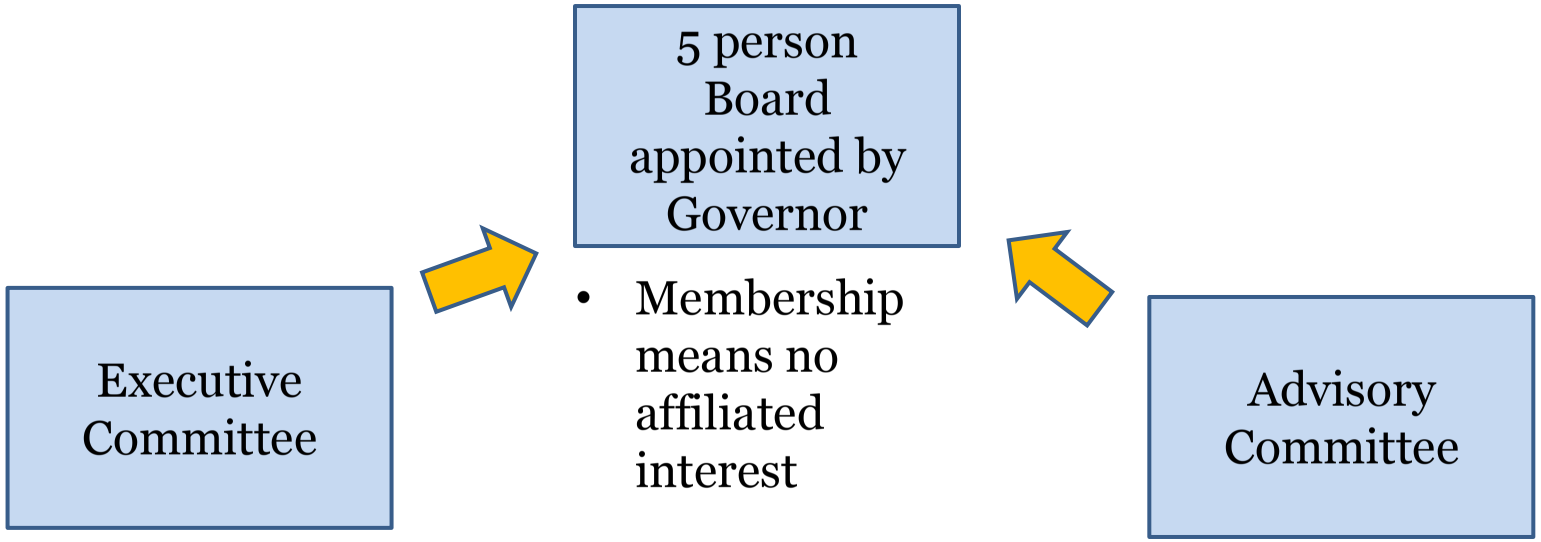
10 person self-renewing Board

- Membership means no affiliated interest

Management Committee

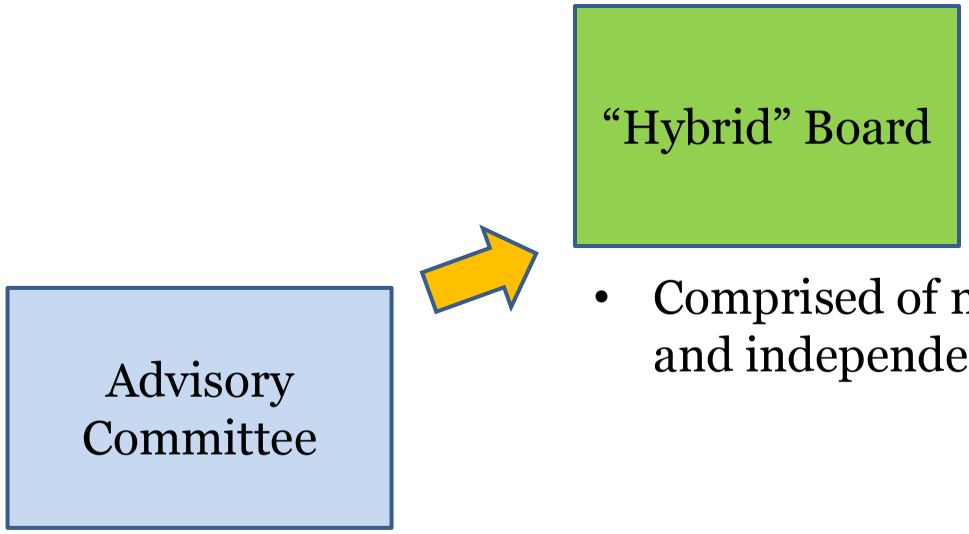
- Public interest groups in addition to market participants
- Similar voting "sectors"
- *Share governance with Board*
  - *Approvals by both bodies required for filing to take effect*

CAISO



- Executive and Advisory Committees have no legal authority over Board, and membership is appointed by the Board.

ERCOT



- Comprised of market representatives, consumers, and independent members

Comprised of stakeholders

Lessons Applicable to Alaska: Board not structurally independent?

- Utilities may insist on maintaining a direct voice
  - History of GRETC and generally observed sentiment of Railbelt utilities to have control
  - Currently participate in management committees for State-owned projects, e.g. Bradley Lake and the Intertie Operating Committee

Lessons Applicable to Alaska: A different type of independence?

- Governing body may need to be structured to ensure that no single party can capture decision making functions ("independence from CEA")
  - History of distrust among some utilities
  - Uneven levels of in-house expertise
- How to accomplish?
  - Voting rights to give any one party veto?
  - Voting rights diluted to prevent undue influence

Lessons Applicable to Alaska: Board Dilution?

- RCA ex-officio membership
- Transco membership
- Some degree of IPP participation
- Other non-utility interests
  - Consumer
  - Conservation
  - Etc

Lessons Applicable to Alaska: Board Qualification and Compensation?

- To ensure against capture of non-utility members, board membership may need to be:
  - highly qualified
  - substantially compensated

Lessons Applicable to Alaska: Advisory Committees?

- Probably a good idea
  - Conduit for technical advice
  - Capitalize on broader base for technical expertise
  - Increase opportunities for stakeholder input
- Recommend against decision making authority
  - NYISO suggests vulnerability to gridlock
  - Perceived vulnerability to 'capture' (uneven distribution of technical expertise)

Questions?

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I-15-001
Alaska Railbelt Electricity System

Policy Decisions:
Towards an efficient and effective Railbelt

5/20/2015

ACEP
Alaska Center for Energy and Power

Legislative Charge

RCA should recommend:

Whether creating an independent system operator or similar structure for electric utilities in the Railbelt area is the best option for effective and efficient electrical transmission.

Reasons for Thinking the Railbelt Is Less then Efficient?

- Economic dispatch
- Generation planning and construction
- Transmission planning and construction
- Service reliability
- Non-billed values

One slice of perhaps Not Widely Appreciated history

- Issue of Railbelt organization and consolidation substantially precedes 1998-era B&V study
- U-82-47 (11), issued in 1985 addresses:
  - Potential gains from more coordination (G&T)
  - Commission authority to force this
  - Past animosity among HEA-MEA-CEA
  - Influence of utility boards by management
  - Agreements by HEA-MEA-CEA boards to mutually cooperate to form a G&T (stillborn)
  - Difficulties in obtaining adequate capital

Economic Dispatch: Transmission Upgrades

- "Economy energy" transactions occur now
- Modeling suggests modest gains could be had
  - B&V 1998
  - EPS 2014; ACEP 2015
- Biggest gains only possible with more robust transmission infrastructure
- More redundant transmission infrastructure may or may not pay for itself with dispatch savings alone
  - Probably not a barn-burner against existing rates
  - Unlikely to be a massive burden either
  - Greater transmission would provide improved reliability, resiliency, optionality

Generation: Planning and Construction

- Some inter-utility co-operation
  - E.g SPP
- Atomistic investment appears to inefficient *compared with joint planning*
  - Comparisons with 1998, 2008, 2010 B&V studies
  - Informal conversations with utility executives
- RCA lacks tools to promote regional efficiencies
  - Atomistic IRPs, but no 'global' planning process or citing authority to enforce

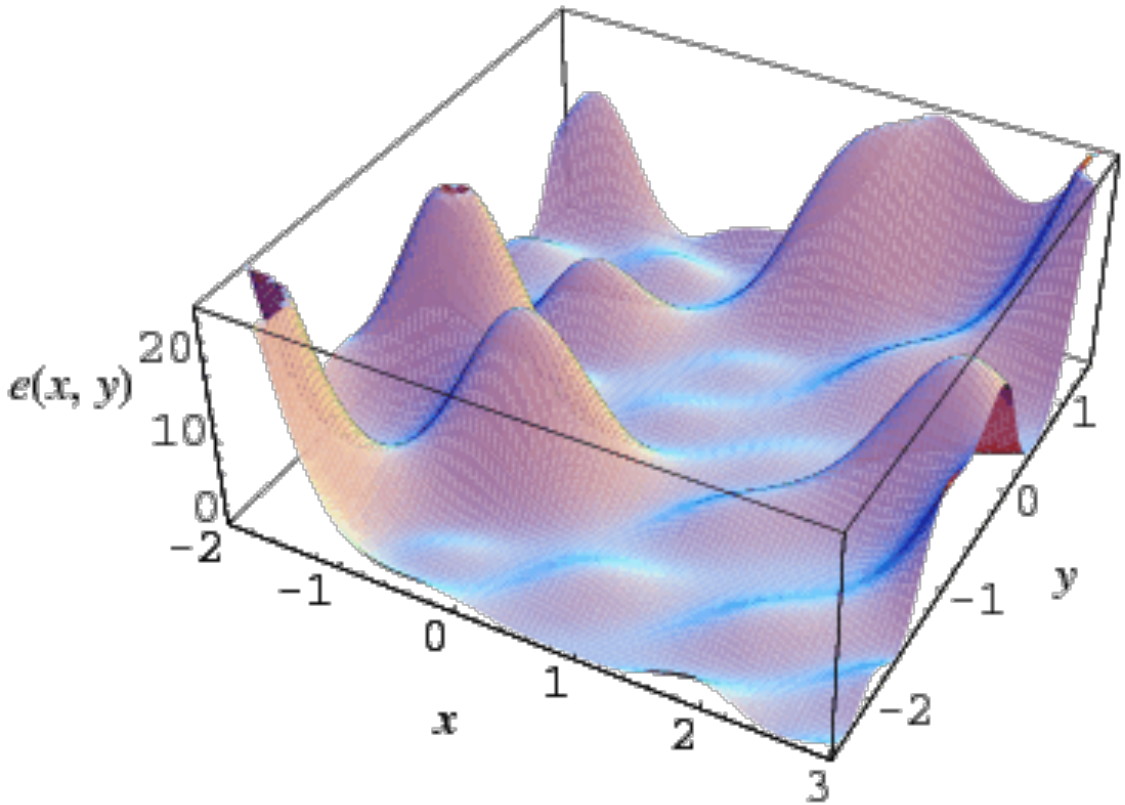
Transmission: Planning and Construction

- Inter-utility transmission curtailed by “free rider” problems
  - Leads to underinvestment, generally
- No ready Railbelt business model to support inter-utility transmission planning/construction
  - No firm bi-lateral contracts
  - No unified Railbelt Transco

Reliability: End Results vs Process

- Results
  - "Good", compared to what?
  - Inadequate systematic data on results
  - Who should decide? (Governance; non-billed values)
- Process
  - Voluntary
  - Lacks teeth among adherents
  - Transmission system lacks redundancy
  - Transmission system lacks good business model to ensure future reliability

Efficiency
Local vs. Global



"Effective" *and* "Efficient"

- ~~Does a business case exist for new transmission?~~
- ~~Is there a process for determining **and enacting** appropriate system-wide upgrades?~~
- ~~Do utilities have ready access to capital they need to provide affordable, reliable service?~~
- ~~Do each of the utilities have the breadth and depth of expertise that would be helpful?~~
- ~~Do organizations foster replacement and cultivation of institutional knowledge?~~

Short-comings result from balkanization, not intentions

- Electricity system must:
  - deliver on demand
  - deliver reliably
- Therefore:
  - Need “excess” capacity
  - Must operate within constraints
- Many operational constraints!

A mathematical fact

- Any complex system will operate more efficiently with fewer constraints
- Inter-utility coordination allows for relieving constraints through shared resources
  - Reserves (spinning, capacity)
  - Regulation
  - Human capital
  - Hydro resources
  - Transmission cost recovery responsibility
  - Others…

Some Necessary Functions

- Load balancing
- Security-constrained merit order dispatch
- Transmission scheduling
- Operation of Transmission Tariff
- Collecting and distributing revenue for transmission and generation assets
- Transmission and Generation planning
- Transmission construction and operation
- Reliability standards: development, refinement, adherence to and certification to perform within

Types of Institutions ('definitions')

- Transco:
  - Entity that owns and/or operates transmission assets
  - Operation not shared with generation companies
- Dispatch entities
  - "ISO": overseer of competitive wholesale electricity markets w/structural independence from gencos
  - "Tight pool"/USO: centralized dispatch authority with merit-order dispatch
  - Loose pool: utility responsibility for control area services retained; reserves sharing; coordinated not centralized dispatch

A couple of transco/dispatch entity Arrangements

- One institution houses dispatch functions, and also owns and operates transmission assets
- Dispatch entity leases or otherwise acquires operational control of transmission assets, but does not own them

Economic Opportunities

- Each of the previous types of institutions could provide the first step on a path towards more integrated, Railbelt planning and construction
  - Foster regional assessment of reliability needs and enforcement of reliability standards
  - Capturing economies of scale and scope in generation addition
  - Improved ability to incorporate IPPs/Renewables
  - Reduced litigation (?)

Policy Actors
Relevant to path forward

- Utility management:
  - Where much of the technical expertise lies
- Non-profit Utility boards
  - Where Local Values can be expressed
- RCA
  - Regulatory expertise but uncertain authority or policy mandate
- State Legislature
  - Least expertise, potentially much authority, diminished carrot-offering capacity

Iron Quadrangle of Inertia

- Technical expertise in **utility management**, among whom is a long history of mistrust
- **Elected board members**, often lacking expertise, can be captured by managers
- **Regulators** may have some powers have historically been extended little trust in policy
- **Legislature** with power, but no expertise, unsure of what to do

Policy Innovation, Coercion and Negotiation

- Self-organizing utilities?
  - Allow those with expertise, and responsibility to reflect membership interests, to figure it out!
  - Market failures (no competition, unbilled goods) call into question whether current governance efficiently reflects ratepayer values

Policy Innovation, Coercion and Negotiation

- Who should determine 'right' level of reliability?
  - Do customers convey reliability expectations, with management following?
  - Utilities, practically speaking, now condition level of reliability their customers demand
  - Commission has statutory authority within (and possibly across) service territory

Policy Innovation, Coercion and Negotiation

- If not self-organizing, then:
  - Legislative design?
  - RCA-guided process?
  - Legislative enabling of RCA-guided process?

Policy Innovation, Coercion and Negotiation

- How to address utilities that do not want to join?
  - Some degree of 'coercion' may be needed
    - Ideally it is never operationalized
    - Additional RCA authorities may be helpful
      - Defensive: e.g., citing authority
      - Pro-active: enhanced standards around 'prudent utility practice' (?)
  - Styles of coercion
    - "Designing the watch" (legislatively)
    - "Explain to me why you haven't succeeded" (backed with the hammer of 'if you don't do it, we will')

Going-forward issues

- Opportunities for ‘go it alone-ers’ to be severed?
  - Fact specific
    - Technical
    - Economic
    - Political
- How to handle AEA-owned assets?
- RCA’s lack of jurisdiction over the Bradley Lake Agreements

Going-forward issues

- Asset transfers or sales?
  - Co-op issue of voting rights
  - Not necessary for Transco formation
    - May be helpful for utility balance sheets
  - Not necessary for enhanced economic dispatch
- Who pays for new transmission assets?
  - Full socialization (e.g. ERCOT) or
  - Generator pays full cost of radial line, or
  - Some fact-specific allocation of costs?
    - Clear rules are helpful

Going-forward issues

- Competitive entrants (IPPs)
  - PURPA-like requirement for purchases?
  - Regulatory approval of PPAs?
    - "Must run" bi-lateral voluntary deals
  - Competitive bidding for new generation needs identified in regional plans?
- Rate-making complications
  - Transition rates towards postage stamp ideal?
  - Allocation of costs based on demand?

Necessary enabling conditions: The Need for Resources

- Currently RCA is not resourced to manage this effort
  - Time
  - Staff
  - Mediators
  - Dollars
- Legislature should empower RCA to get enhanced resources through RCC

Desirable enabling conditions: Enhanced RCA Authority

- Clarifying Commission's jurisdiction to extend not just within a CPCN, but across CPCNs
  - "Prudent utility practice":
    - Economic dispatch
    - Some reach towards transmission planning (?)
  - Reliability
- Siting authority (where vs. **what**)
  - Backstop tool to promote joint construction planning
  - Check on 'gold plating' transmission construction by an IOU transco

Helpful measures to facilitate new institutions and infrastructure

- Legislative endorsement for RCA to promote a more efficient and effective Railbelt system
- Pledging of state assets (Intertie, Bradley Lake)
- "Carrots" to facilitate transmission construction
  - Collection of IDC pre-operation
  - Securitization legislation to allow on-bill charges for new construction

Conclusions

- Legislature probably has some necessary roles:
  - Increased RCA resources are necessary
  - Increased RCA authority could be helpful
  - Provide RCA tools to incentivize new assets
- RCA also probably has necessary role:
  - Rulemaking processes to sort through issues
  - Coercion as backstop to guided voluntary if directed negotiations ("figure it out or we will")

Questions?

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STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners: Robert M. Pickett, Chairman
Stephen McAlpine
T. W. Patch
Norman Rokeberg
Janis W. Wilson

REGULATORY COMMISSION OF ALASKA
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501

Public Meeting
May 27, 2015
9:00 a.m.

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P R O C E E D I N G S

CHAIRMAN PICKETT: Good morning. This is a public meeting of the Regulatory Commission of Alaska. It is Wednesday, May 27th, 2015. It is approximately 9:02 a.m. With me on the dais are Commissioner T. W. Patch, Commissioner Stephen McAlpine, and Commissioner Janis Wilson. And I'm Bob Pickett, Chairman of the Commission. Commissioner Norman Rokeberg will not be with us this morning.

Agenda item number 1 is public participation. I will say that if you have extended comments you would like to make on agenda item number 2, you can hold your comments until we open that agenda item. But any other comments before the Commission this morning -- is there anyone in the Anchorage audience who would care to address the Commission?

Is there anyone online who would care to address the Commission? Hearing none, we will close agenda item number 1.

Agenda item number 2 is I-15-001 in the Matter of the Evaluation of the Operation and Regulation of the Alaska Railbelt Electric Transmission System. Since early April public

meetings you have had the pleasure of listening to a number of presentations from Dr. Scott with a little bit of questioning and comments from the Commission. The format of the public meeting this morning is going to be a little bit more flexible, more open, some discussion from the dais on the part of the Commissioners. But I would like to extend an invitation to anyone in the audience who would care to comment, critique, question anything they have heard, whether it be a global sort of questioning or very specific.

So is there anyone in Anchorage at this time who would like to raise any questions or thoughts for the Commissioners to think about before we make our determination later in June?

You'll have some other opportunities. So, you know, I'm putting you on the spot. So think about that. One of the challenges the Commission has in this charge that the Legislature has given us is we have to weigh all of the modeling and potential benefits that have been presented to us, you know, since the first of April, roughly. And, in actuality, for probably about a five-month period before that with informal conversations, discussions, and working with Dr. Scott.

And I'll put my cards on the table. I'm sort of a cost/benefits sort of guy. If you're going to do something that's fairly significant and dramatic, I've got to be convinced that the benefits are actually there to make the efforts worthwhile. And I'm cynical.

When I observed -- and I perhaps was burned by the GRETC thing as far as participation in that. And my takeaways from that were not particularly positive, I guess, is a charitable way to put it. I appreciate the intentions of all the parties in the effort, but when I watched that political process unfold and I contrasted that with what I became very aware of in a number of rate cases, the disconnect there was quite overwhelming.

And as we got into this process and, you know, going even further back in the history clear back to the mid 1970s, on an individual basis I think the utilities have done a good job of, you know, keeping the lights on and dealing with what they had to deal with in some fairly challenging circumstances. And there have been examples of bilateral agreements that have worked to the benefit of both utilities and the ratepayers.

And, you know, particular projects like Bradley Lake and some of the Intertie projects that we're fortunate to have in place.

But looking on a going-forward basis and when you talk about a major institutional restructuring to capture benefits that I think are out there -- I mean, that was one of the first questions is: Is there any reason for us to believe that the Railbelt electric system is operating on a less than optimal basis? And I think if you ignore all the utility boundaries and look at it as a whole, that -- for me, I say, yes, it is operating on what probably is a less than optimal basis.

But if you look at each of the individual utilities operating within their own certificated service area, they're making rational decisions doing the best they can given the hand they've been dealt. So the question is: Are those benefits significant enough to make it worth the effort to move forward and create something different?

And, again, I'm just -- this is just me. This has nothing to do with the other Commissioners. And they can hit me or kick me or do -- and, trust me, they will when I get off the

dais if I say something too out there. But I think the simple fact of the matter is, it's highly unlikely that the Legislature is going to do a significant cramdown of any sort, particularly if it is associated with a check as an incentive.

So they can perhaps do certain things with our statutes. And right now there's probably five different bills in varying stages -- you know, some are duplicates in the House and Senate side -- that either are directing us to do another report by 2016 or some sort of an effort to try to create a competitive wholesale electric energy market or something that focuses more specifically on the transmission with some new governance structure. So those little pieces are out there and have been carried over from the last session to this session.

And we discussed one at length that we had serious issues with and have worked with the bill sponsor, and there's a potential committee substitute that has not been active at this point. And so just being realistic, what is it specifically we can incorporate in our report that will give the Legislature something to work with,

realistically?

Again, that doesn't involve them writing any kind of a check or forcing the utilities into doing something that the first step would be into court on probably some kind of a takings-type argument. So that gets us to the Commission. You all have different ideas as to what the Commission can and cannot do. We asked you -- we gave you a month. You're not on the same page. I think that's self-evident. And so given the controversy over the extent of our regulatory and statutory authority, what is it -- what is realistic for this Commission to do?

And just having been a Commissioner for eight years now and knowing the Commissioners we currently have on this Commission, I don't think it's realistic that you're going to see the Commission do some sort of an expansive cramdown. Does that mean there aren't actions that we can take that would perhaps encourage? I think there are.

So what it's going to come down to for us -- we saw a lot of scenarios on -- different planning scenarios for costs and for benefits. And I think it's important for us to move forward with a high

degree of humility. There's nobody sitting in this room with a straight face that can tell me you predicted what happened to hydrocarbon prices 12 months ago with any degree of exactitude. And when we look at the modeling and the assumptions in each of those scenarios, they are driven by those kind of assumptions, among other assumptions. And so, you know, we have to sort of look at what are the most probable or likely outcomes and the benefits and costs associated with those. And does that make the effort worthwhile both for the utilities, the Commission, and anything the Legislature may or may not do?

So before I go on ranting anymore I am going to give other Commissioners the opportunity to give their initial reflections, keeping in mind this is not an official vote. We're just letting you know what our initial takeaway is. And, again, at the next public meeting next Wednesday we will have a couple of excellent presentations, I'm sure, that will prod further thought on the options before us.

So, Commissioner Wilson, you're always the voice of reason and calm on this Commission. Would you please grab the microphone.

COMMISSIONER WILSON: Maybe I should go last, then.

CHAIRMAN PICKETT: Commissioner Patch?

COMMISSIONER PATCH: Thank you, Mr. Chairman. And thank you, Jan, for being willing to take on the hardest lift at the end to bring balance and vision.

We've known about this charge from the Legislature for approximately a year. It's an expansive charge. And a couple weeks ago I had the privilege of traveling east and visiting with friends of mine at the FERC and doing some other business on behalf of the State. While I was there, I took the opportunity to ask the FERC commissioners and senior staff in the electric realm: Had an RTO or an ISO ever been brought to fruition in a period of one year? Even a recommendation regarding that? And they laughed. And it was good that humor was afoot in the room.

I would like to thank those who brought about this charge for their faith in this agency as it was evidenced by the charge, by their lobbying effort that the assignment be given to the agency. That there seemed to be both in those recommending

the undertaking and in those directing the undertaking that this agency works on principles of deciding matters on a developed record and goes about developing the record in a careful fashion. It is nice to feel that faith is placed in you for who you are and how you go about doing your job.

But to those same persons, I would ask that in the future they perhaps be a bit more realistic and consider matters of funding and resources and time commitments that presently exist on the agency. Our work doesn't stop. I'd also like to thank a great many people for affording me an education, which is somewhere on Maslow's needs ladder. But for me it's enjoyable.

We have approximately 30 comments that have been provided to us over the course of this docket. Some are few pages and some are multi-hundred pages. We have commenters beginning with Mr. Mitchell on behalf of the Alaska Independent Power Producers Association. There's no prize for being first, but Mr. Mitchell is often before us.

We have commenters from across the spectrum of those who would assist us. They have been here. They have met with industry. They have

occasionally met with us, and their input is valuable. We have very good comment from State agencies, the Alaska Energy Authority, and the office of the attorney general. And we have a good deal of industry comment.

On my behalf, I've read the comments more than once. It's interesting late night reading. Much like television, it contains a certain amount of comedy and a certain amount of drama and a certain amount of self-praise. And it's more fulfilling than watching "The Real Housewives of New Jersey." But it does sometimes make you put the paper down and think about what you've read and how to apply it.

In the realm of those of you who don't stay up late and watch "The Real Housewives of New Jersey" but rather prefer your television on Sunday mornings where you have talking heads, there are some policy questions that have not been addressed. Now, maybe that falls to us. But it would have been helpful to have some of that. So if those who will be returning to Juneau in the next session to read the report and discuss it feel inclined, I would encourage an open policy discussion with the Legislators who you will be

asking, perhaps, to provide us some guidance.

And if your television fare is not the housewives nor the talking heads but rather those programs you might find late in the evening on PBS, something like "Machines of War," it would have been helpful and I think beneficial for all of us if we'd availed ourselves -- if you had commented differently and if we perhaps had availed ourselves of some technical conferences.

It would have been helpful to have: Why we should take an action? And how it benefits ratepayers? And what are you willing to give up for the common good? And what is the order in which our actions should be recommended? So there's some nuts and bolts missing. But for those of you who did in some measure touch upon those, I can say that those comments were, for me, the most helpful.

As the clock now ticks somewhat louder marching towards the date on which the report is to be filed with the Legislature, I confess to some fears. One of the fears is I don't sense a great deal of consensus about the task we were given. And, as I just mentioned a minute ago, I don't sense a great willingness to sacrifice for

the common good. And those who would beg and plead that I should not gore their ox seem somewhat willing to have me gore their neighbor's ox. And that's problematic. I would as soon not gore anyone's ox or gore everyone's ox. I don't know how to do otherwise.

This morning I received an article that I'm going to read a little bit from. State utility commissioners in all 50 states are under a lot of stress. First, they must formulate and plan for the future of their state's electrical grids. And at the same time they must keep their eyes on developments in their own State Legislatures, in Washington, D.C., on world energy markets, on EPA with its clean air plan, and those are a lot of elephants in a very small room. It could be argued that state utility commissioners have a far worse job than the Maytag repairman. Instead of having nothing to do, they have everything to do and they must do it out of an unstocked truck and with a limited toolbox.

I have come to the conclusion that there are ratepayer benefits that can be achieved by institutional change. Concepts that have been bandied about in this docket and elsewhere such as

economic dispatch, coordinated standard operations protocols are achievable. But some things are not known. The quantum savings, how the savings should be allocated are issues that remain unresolved. And because those issues remain unresolved, I am not at all certain about the value proposition. So, for me, whether creating an independent system operator or similar structure for an electric utility group in the state of Alaska Railbelt area is the best option for effective and efficient electrical transmission is a question pending. But I have come to the conclusion that it is likely not the best option. And I am certain it is not the first option.

For me, the RCA, if it is going to answer this question and plan for the future and enable healthy utilities to operate and deliver valuable services appropriately priced to ratepayers, must have greater resources and must have greater independence. And once those are achieved, my conclusion is that the agency should have tools added to its toolbox so that it doesn't face what has happened in the last ten years.

The construction of excess generation, the

concerns developed about transmission, the inability to plan for co-optive participation with one another to the degree that they -- that companies are complaining about that being missing today. We should have, I believe, added to the toolbox in some manner by statutory directive or by regulatory adoption an integrated resource plan and siting authority.

And once those are there and we have the technical conferences I referred to as feeling might have been beneficial, then we can ask one another face to face, eye to eye in heated conversation, if necessary, but in close proximity always, what order should we do things in? How do we get there? And we can then conclude the planning and take the action.

So as Yogi Berra observed, "I came to a fork in the road and I took it." And remember this, Yogi played for Casey Stengel. And Casey Stengel observed, it's very difficult to make predictions, especially about the future.

Thank you very much, Mr. Chairman.

CHAIRMAN PICKETT: Commissioner McAlpine?

COMMISSIONER McALPINE: Yogi also

said: No one goes to Coney Island, it's too crowded.

Just as a little background, the discussion came up with Dr. Scott that this has been an ongoing matter for at least 20 years. And I chimed in that it's been going on for 40 years that I know of. And I've watched the generation capacity throughout Alaska develop from the time of the Four Dam Pool and some of the local wars that went on back then to the Railbelt Energy Fund, to the wars over how that fund was to be divided over -- Bradley Lake was a consensus matter and has proved to be very successful.

But in terms of generation and transmission, those wars were fought between the utilities. And, quite frankly, I think some decisions that were made were not made in the best interest of all of the ratepayers, of all of the consumers, but rather in the best interest of each individual utility as they saw it at the time. And to that degree I agree with Commissioner Patch and with Dr. Scott's observations that we may be closing the door at this point after the horses have exited and gone over the hill.

I look at the generation that has been

developed and it causes me to wonder what technologies are going to be developed that would cause these to be obsolete in the very near future. At the present time, while looking back, the Internet is what? 25 years old at this point in time and has literally changed the face of communications across the globe.

In Japan right now consumers are being subsidized with hydrogen generation. Is that the wave of the future? I don't know. In several universities right now battery storage is being studied. Is that the wave of the future? I don't know. But what we do know is that we are tied at the present time to an overcapacity of generation whose source is hydrocarbon. Is that the wave of the future? I doubt it. But that's what -- that's the hand that we have been dealt.

It's unfortunate that more of the available funds weren't put into the transmission arena. Because, as Dr. Scott pointed out and other studies have shown, if we had had the wherewithal to upgrade our transmission facilities, we could achieve some significant benefits. I will say, as a practical matter, as how we all in this state observe the political arena, the likelihood of the

Legislature coming in and granting any additional money for transmission upgrades is almost nonexistent.

Right now the money that has been spent over the last several years on big projects whether it be the Knik Arm crossing, the road north of Juneau, the study of the railroad extension to Nome, the ferries being built in Ketchikan, the Susitna dam project, I think all of those are going to come off the table. And they're going to come off the table as a result of the realization that there aren't a lot of dinosaurs stomping around the North Slope to satisfy our insatiable desire for oil and the revenue that it produces. It's a finite resource.

And I think it is the third awakening that we've had. But I think at this point in time, this is the real one. This is the one that's going to cause the Legislature to step back and say: We're going to develop a budget that we can live with and we can sustain over time. So having said that, I think we're all on our own with respect to the issues that we face.

I, like the Chairman, don't believe that we should be shoving anything down anyone's throat.

I think that at some point in time the utilities have to come together in a cooperative fashion and make a determination of what is in the best interest of the -- I will call it the pooled ratepayers, and who's going to have to make what sacrifice in order to achieve that?

I think that having said that we're not likely to get additional funds for additional transmission, that that puts us in a position of perhaps putting Homer and Golden Valley out on the ends of the spectrum, and the three utilities in the center in a position where they're going to have to come together and begin to cooperate. Is that a shove-down from this Commission? Is it a shove-down from the Legislature? I certainly would prefer not.

I think it's fair to say that no one wants to be in that position. But I think that there are some gains to be had by doing that. I think that I could fairly stand before the Legislature and say that's my honest belief. Are we going to get there? I don't know. But I think that my viscera at this point tells me that that's information that I would be willing to share with yourselves, with the public, with members of the Legislature.

In the hope that they don't have to adopt legislation to achieve it.

Having said all of that -- and I intended to be very short. Having said all of that, the one statement that Dr. Scott made at the end of his presentation that I would agree with wholeheartedly, we're not going to study it again. And I would tell the Legislature that. I would tell the Governor that. I would tell you all that. Tell members of the public. It's time we stop studying the matter and get on with the future.

Thank you, Mr. Chairman.

CHAIRMAN PICKETT: Commissioner Wilson?

COMMISSIONER WILSON: Thank you, Mr. Chairman.

I have not heard anything that I consider unreasonable from other Commissioners. I think history is important. And I think that our report should include as complete a history as we can give of the last four decades of trying for inter-utility cooperation. It's been a history that I've personally observed. I've been associated with the Commission in one way or

another for most of that time.

And we -- it's something that -- there was a status que that existed up until a year and a half ago. And things have fundamentally changed in the last year and a half. We've gone from three generating utilities with Homer generating a little to five generating utilities. And only time will tell what that fundamental change means for possible cooperative efforts.

I'm not going to be pessimistic and say it makes them harder. It just makes them different. And I'm hopeful that that change will move things off the dime a little bit. Because we know that -- I think Chugach has been the gorilla of the Railbelt. And Chugach no longer is in that position. And I think that thinking of Chugach in that way is something that is in the past and should be thought of as in the past. And Chugach should be thought of as just one of the five utilities now.

And so I'm hopeful that because of that we can look at some change. But I do think, Mr. Chairman, that it is important to put the entire history and put it into context because it has been pretty much continuous. And I just want

to speak to the last some-odd years that I've been a Commissioner. We had in 2007 a petition from MEA to -- and it asked that the Commission adopt regulations governing the creation of a generation and transmission cooperative or a mandatory unified power pool for the regulated electric utilities located in the Railbelt. We went through that docket. We had comments. That docket lasted for two years.

That was at the time of the REGA study. And I will channel Commissioner Rokeberg because he's not here. He was chairman of the REGA study. And he -- I think everyone was hopeful that both the REGA study and the successor regional integrated resource plan study would move people toward change or would result in some kind of mandated change.

And, in fact, the reason why the MEA docket, which was R-071, was closed was that the Commission believed that the REGA study should go forward. And at that time there were actually some bills in the Legislature in 2009 to help with this. So that's just an example of one of the many, many, many studies and working groups that have tried over the years to unify generation and

transmission.

And now we're talking about because we have the generation built for probably a generation, not to -- we're now on to transmission. And I think that I don't have a lot to say in addition to what other Commissioners have said about how we can move forward with generation.

I think one of the things that we haven't talked about this morning is reliability. And I think if there is legislation that helps, that gives different authority to the Commission -- and that is entirely within the province of the Legislature. This Commission only administrates the laws that the Legislature passes, and the fundamental policies are done by the Legislature.

But I think that it would be nice to have clear inter-utility authority for reliability. I think we certainly have -- and I think all of you acknowledge that we have reliability authority. I think there's just some disagreement on whether we can do Railbelt-wide reliability. But I personally believe that we have that authority already. But it would be good to have it clearly stated that we have inter-utility reliability authority.

And I think that -- I hope that we will have some more comments from the Legislature -- I mean, from the utilities. I hope that -- I would like, Mr. Chairman, to have a workshop with the utilities. Commissioners and utilities sitting around the table talking about this before we actually submit the report to the Legislature. And I hope that will be able to happen in the next month. I don't know if that's possible, but that's what I would like to see.

CHAIRMAN PICKETT: Thank you, Commissioner Wilson.

I, too, have shared Commissioner Wilson's concerns about reliability. My sense is the system, though it has functioned in a very reliable fashion as long as I've been in southcentral since the mid '70s with a few exceptions -- and that's to the credit of all the people involved with making things work -- but it is aging. There are certain segments and components that you just sort of wonder how strong or fragile it may be. And the lack of redundancy in certain areas probably is a concern to me.

But I would say an overarching concern is if some event were to happen or there were some --

there was some significant transmission project that absolutely had to be done that was very pricey -- I'm talking 150, 200 million, something like that -- and it crossed two, three, or four CPCN service areas, I question whether the institutional ability to pull it off exists at this point in time. So that's just one of the things I've been sort of mulling over for quite some time.

The first pipeline docket I was on was the Beluga pipeline back in 2008. And it was a traumatic experience. In fact, at the tail end of it I literally got pneumonia so I could get out of the last two days of hearing, and it seemed like a worthwhile tradeoff.

It was -- it was during those proceedings I developed the metric of number of attorneys per mile of pipe. And we got up to about 1.7 for that particular -- and it was largely a reflection -- had a very balkanized gas pipeline system in the Inlet that was historically -- it was sort of irrational, to put it mildly. Through a bunch of circumstances, that whole balkanized pipeline system -- and it's largely due to a change in ownership -- has been unified. And there's still

some controversy and questions about certain aspects of it.

But I think by and large going forward it's going to make it better for the producers in the Inlet, for the utilities, ultimately. And perhaps there are -- I don't want to go too far out on a limb here, because it may take a new institutional structure. And I'm talking only in terms of the transmission assets. I think it's a mistake to pull generation into that discussion because the Alaska statutes are very clear. Utilities have gone out and invested, you know, from Homer to Golden Valley and all points in between about a billion-and-a-half dollars in new generation when you add it all up.

And the Alaska statutes say whether it's for the Municipality or the co-ops, that debt will be paid off, period. End of discussion. No ifs, ands, or buts. We're not Greece. We're not Venezuela. We're not Argentina. So that discussion needs to be taken off the table. Because it's naive to think the Commission is going to open some sort of a prudence review on a co-op where we go: Okay, co-op, you really messed up by doing this. Therefore, we're going to order

the co-op members to pay back the ratepayers somehow through some -- I mean, you just sort of work it through, and there is no mechanism to do anything that makes any sense whatsoever. So it's foolish to waste time going down that path.

I do agree with Commissioner Patch and some of the things that Commissioner McAlpine said. And on a going-forward basis in the future, at some point that new generation is not going to be on the table for quite some time. The fact is it will be replaced down the road with something. Maybe new technology. Maybe something entirely different than what we're thinking of.

And some of the lead time on planning and executing -- you know, you're talking seven to ten years. And so when we get out to 2025 or whatever, as crazy as it sounds to us today, utilities will start to have some of those planning long-term discussions. And it would be nice to have the appropriate tools in place to, you know, rationalize what happens.

And a lot of how this generation is viewed whether it's, you know, significant overcapacity or just about right, is going to depend on what happens to the rest of the economy. I mean, let's

face it. Chugach -- you can make an argument at certain points during the '80s that they put way too much generation in, and they were crazy to do it. And then as things recovered, they started to look like they were pretty smart, you know, with the growth in Anchorage and the Valley. And so with the lead time you just can't get too critical in short periods of time. You have to take a little longer view.

But I do think that for this snapshot of time when you add everything up, there probably is a pretty good argument that the amount of generation is more than what it needed to actually be collectively, not on a utility-by-utility basis.

So when you look at the transmission, I do think that there is a powerful argument to be made for a new institutional structure. Will that actually save money? Depends. Depends on the scenario. Depends on what happens to hydrocarbon prices. Depends on a lot of things. And I don't think that's predictable.

And is the -- are the savings realized sufficient to make it worth going forward? There's arguments there. But I think probably so in the long run. In the short run, I think

there's going to be opposition to it just because we can't dismiss the impact on ratepayers with all this stuff. I mean, we have not absorbed all this new CapX into rates. I mean, this process continues to go on and in the Railbelt will go on through 2017. And when you add up a series of 20, 25, you know, whatever percentage increases -- and not just for the electric, it's other forms of utilities -- the pressure is on.

I mean, we can hope for some relief in natural gas prices in the Inlet. I hope it happens. I'm not holding my breath, because I remember less than five years ago a lot of people in this room were telling us with absolute certainty, we are going to be importing LNG by 2014. And some of the utilities were spending significant amounts of money towards that end.

So, again, I think we need to sort of approach this with a fairly high level of humility. But reliability is important. I don't quite know what to make of voluntary reliability standards. We had some filed with the Commission about a year and a half ago. And we appreciate the fact and the effort that was put into those. But enforcement is the key with standards of that

nature. And not everybody was a signatory to the standards.

And then we hear in the context of rate cases or informal discussions, yes, but utility XYZ is not conforming to this. And we don't know whether they are or they aren't. But it's sometimes used as argument. And I sometimes wish I could be a bug on the wall in some of these inter-utility discussions and figure out what actually is going on. That will never happen.

So with that mini monologue I will turn back to the Commissioners and see if they have additional thoughts.

Commissioner McAlpine?

COMMISSIONER McALPINE: I would like to second Jan's motion, that is to have a sit-down with the utilities. I think that would be very helpful. And too often we get into this mix that you have to avoid ex parte communications. And I think that it would be very helpful to have a workshop with the utilities. I don't know that I would want to mandate their presence, because that starts you down the road of apprehension.

But I think it would be very beneficial for

my own self and, I think, too, the rest of the Commission to have a workshop of that nature.

CHAIRMAN PICKETT: We'll certainly work towards that end. Again, the calendar is pretty tight, but -- and we have told the utilities to try to get their at least written comments in to us by the 17th of June. So we'll look at the calendar and see what we can figure out on that.

So any additional Commissioner comments? Thoughts? I will now open it back up to anyone in the hearing room if you -- after listening to us carry on, if you'd like to comment, respond, throw a tomato at us. I don't know. Whatever suits you.

Is there anyone online who would like to offer any comments at this point? Okay. Hearing none --

MR. WRIGHT: Commissioner Pickett?

CHAIRMAN PICKETT: Yes. Please identify yourself for the record.

MR. WRIGHT: Yeah. This is Mike Wright with Golden Valley Electric.

CHAIRMAN PICKETT: Oh, I was hoping you would be online, Mike. You're always good for

comments. Please proceed.

MR. WRIGHT: Yeah. That's a problem, I think, somewhat.

But I am going to make a general observation comment, if you don't mind. And, as you mentioned not speaking for the board, I'm not speaking in general for Golden Valley. Although, Golden Valley will be making comments and submitting them. We're getting together on it. And so there's just some general observations, things that I would like to share, and I'll take this moment to do that.

One thing that Commissioner Wilson brought up that was one of the points that I've been thinking about over the last two weeks is we are at a crossroads. And I'm going to phrase it a little bit differently. But we have the -- it's almost as if we are a family growing. And there was a parent at one time. And there was some siblings, and that's like MEA and HEA.

But now they've left the nest and we're all equals. And, to me, they're all doing generation. They're all doing transmission. They're all doing distribution. We're all having the same challenges. Some are more knowledgeable because

they've been in that game for the 40 years. And others are just learning and some things like that. But it gives us the opportunity -- and maybe I'm being too much of an optimist. But it's given us a new opportunity to move forward as equals and try and craft agreements that are mutually beneficial across the board.

One of the challenges -- and I think you've seen that from the study and some of the things we're looking at as we're investigating TRANSCO -- is there are differences between the utilities of what -- of how they've done business or what they've had that changes in the future don't provide the same benefits to everybody in the same way.

I mean, you can look at -- and I'm saying this generally because other people are way more knowledgeable of their system than I am. But in general, like, ML&P has a lot of generation, has a large load. Doesn't really rely on an interconnected grid as much except to make sales and maybe get their Bradley shares. So what's in it for them moving forward is a little bit different than like Chugach -- or, I mean, Golden Valley, which does rely on the Alaska Intertie to

get economy power sales from our neighbors in the south. And we've been doing that since it's been built from to degree to another, except for the years like you mentioned when we didn't when gas just wasn't available. We couldn't get anything. We had to rely on oil. And at that same time oil went to $140 a barrel, which was fairly drastic for our cost of power during that time.

Then, of course, you've got Homer and MEA that are just getting out on their own. They don't necessarily rely so much on the interconnected grid, although they have some impacts on the grid. So what's going to be beneficial for them and their ratepayers moving into the future -- they all have things differently. So it's how do you craft a deal -- or one of my concerns, as many have mentioned, if something's crammed down our throat it's not -- it's not the same for everybody in this.

If everybody had the exact same problem with the exact same benefits, it would be so much easier to get together as a group of utilities and solve these problems, but they're not all the same. So that's one of the things I think you as the Commission have heard from many of the groups

and from Dr. Scott. And so it really is -- it's not that people are being buttheads, quote, unquote. There are real differences in what's beneficial to others. And, of course, Chugach, they built out and they did the stuff that they've done to be -- to provide power. And that includes a robust transmission grid. Well, now they've lost that load and they have this robust transmission grid, which costs are now having to be borne by -- mostly by their own ratepayers. So they have their challenges also.

But, ultimately, I think it's -- I am an optimist in that we are our equals, and we can -- I believe it may take some coaching and facilitating. And I know the GM's and CEO's are working together in some aspects. And I see a cooperative spirit among the different utilities in certain areas moving forward. So I'm an optimist on that.

One thing I've always had a challenge with a little bit -- and really this is my opinion. And I do agree that we don't need to do too many more studies. However, any time you mention IRP, IRP is a study. And there is a place and time for regular ongoing studies, because there are changes

in fuel prices. There are changes in loads and things like that. So you do have to do studies on a regular recurring basis. But it does seem like we've studied the whole thing of should we TRANSCO? Should we be USO? Should we be ISO? And all these different things to death. But I do want to point out, we did do the study that called for the $1 billion of infrastructure increase.

And I've said it many times in many places. I'm an engineer. And you would think engineers go: Oh, yeah, let's build. And that's exciting. I have a contrary view on some of the buildout, and this is totally my personal opinion. And just like with any study, it's based on assumptions. And I believe the results of the study were accurate based on the assumption. But some things have changed, and I didn't always agree with all the assumptions.

But because that study went out there and became public and it was that we've got this billion dollars that we have to build, but we don't have the money to put into it. Now you're getting all these people that are equity-type investors -- and nothing wrong with that -- coming up here saying: We can give you money. We can

give you money. And we're getting bombarded.

But that's very interesting and leaves us the ability of maybe what can we do? Can we go with somebody that just invests and the utilities do it ourselves, or do we form a TRANSCO as one of the other equity-type investment people mentioned? So it gives us some opportunities to move forward if we do need to build out.

The point I have -- and this is why I always fall back thinking of the ratepayer. And I always do it. Any infrastructure we add will have a rate increase either for certain utilities or across the belt. Anything else is potential savings from economic dispatch or potential savings from losses. So they're all potential, but the costs are real. So we just really need to be careful as to the future of the interconnected Railbelt.

I will say, by the time any of these things are rectified I believe I'll be retired. But I intend to stay in Alaska. And, as I always talk about, I'll have seven grandchildren by this September. And they're going to be here in Alaska. So I really do have concerns, because I have the ability to talk and do some things, that we need to make sure that we are thinking of how

to keep the costs down for the interconnected Railbelt into the future.

And I think that's about all I'm going to say right now. We'll have -- we'll be -- Golden Valley will make formal comments. And if there is a workshop that we come down and get invited, somebody will attend and come down there.

I will say we are going to be -- most of us that are involved with this will be down at ATC the week of the 17th. So that would be a bad week for us, but there will still be somebody from Golden Valley if that was the case if it was on the 17th.

And I will leave it at that. Thanks for the opportunity to make just a comment of my own.

CHAIRMAN PICKETT: Thank you, Mr. Wright. You made some very excellent points.

You're saying the meeting is on the 17th of June? That Wednesday is a conflict for you?

MR. WRIGHT: We've been invited down and we'll be down the four days: Monday, Tuesday, Wednesday, and Thursday. Two of the days are travel. But there is a meeting down there because there is a working group of utilities that are looking to see if there's a way to get a

TRANSCO to be an effective way to move forward and do cooperation. So we're having a meeting in Wisconsin that week.

CHAIRMAN PICKETT: Okay. Okay. We will keep that in mind. And perhaps -- so if you don't get back until the 18th, it would probably have to be the following week. Okay. We will keep you informed. Thank you.

Is there anyone else online who would like to make comments at this point? Any further Commissioner comments? Questions? Observations? Seeing none, I will close agenda item number 2.

Agenda item number 3 is other business. Is there any other business that needs to come before the Commission this morning? Seeing none, agenda idea number 3 is closed.

Agenda item number 4, does the attorney general have need for executive session?

MR. GOERING: No.

CHAIRMAN PICKETT: Agenda item number 4 is closed.

Is there a motion to adjourn at 9:57 a.m.?

COMMISSIONER PATCH: So moved.

CHAIRMAN PICKETT: Second?

COMMISSIONER WILSON: Second.

CHAIRMAN PICKETT: All those in favor say "aye."

(Collective aye.)

CHAIRMAN PICKETT: Thank you for being here this morning.

(Adjourned - 9:57 am.)

STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners: Robert M. Pickett, Chairman
Stephen McAlpine
T. W. Patch
Norman Rokeberg
Janis W. Wilson

REGULATORY COMMISSION OF ALASKA
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501

SPECIAL PUBLIC MEETING

June 3, 2015
9:01 a.m.

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P R O C E E D I N G S

(On record - 9:01 a.m.)

CHAIRMAN PICKETT: Good morning. This is a special public meeting of the Regulatory Commission of Alaska. It is Wednesday, June the 3rd, 2015; it's approximately 9:01 a.m. With me on the dais are Commissioners Janis Wilson and Commissioner Stephen McAlpine; online we have Commissioners Rokeberg; is that correct?

COMMISSIONER ROKEBERG: Yes, this is Commissioner Rokeberg; and joined by --

CHAIRMAN PICKETT: And, Commissioner Patch, is he online too?

COMMISSIONER PATCH: Yes, indeed, sir.

CHAIRMAN PICKETT: Thank you. Agenda item number one is public participation. Are there any members of the public who would care to address the Commission this morning in the Anchorage audience?

Please come forward to a microphone in the back table there, make sure the microphone is on, and identify yourself for the record. Keep your comments to no more than five minutes, please. There's a button at the bottom of the

microphone, make sure the green light's on.

MR. MYERS: Thank you, Commissioner. My name's David Myers; I'm here on behalf of REAP and all end users on the Railbelt. REAP believes that the -- believes an ISO would support the development of more renewable energy in the Railbelt through the elimination of pancake transmission tariffs. They are currently making it very expensive to move power around on the system.

REAP also believes that there are millions of dollars in collective savings to be gained for consumers if an ISO were established. It also supports the development of more renewable energy -- no, I'm sorry, I missed that part -- but definitely supports the development of more renewable energy on the system. Thank you.

CHAIRMAN PICKETT: Thank you for your comments. Is there anyone else in the Anchorage audience who would care to address the Commission this morning? Is there anyone online who would care to address the Commission? Hearing none, we will close agenda item number one.

Agenda item number 2, I-15-001, In The Matter of the Evaluation of the Operation and

Regulation of the Alaska Railbelt Electric Transmission System; the only thing I'm going to mention in this agenda item is just a reminder that any and all comments from the utilities and all interested parties on this matter needs to be into the Commission no later than two weeks from today, which is the 17th of June. Sooner is better than later because we're in the tail end, and you'll hear some discussions on the 17th and the 24th about what the final determination is by the Commission; therefore, it's helpful for any observations you have on the proceedings and anything you've heard or other things you wish to put into this record, we'd appreciate it. With that, I will close agenda item number two.

Agenda item number three is a Presentation: Chugach Electric Association, Inc. - Methodology for Benefit Allocation. Mr. Galvin, I believe you need to come forward to the computer; identify yourself for the record, and proceed with your presentation. And thank you for being here this morning. Make sure the mic's on.

MR. GALVIN: Thank you very much. My name is James Galvin, G-a-l-v-i-n; I'm with

Teneo Consulting, LLP. I'm here today to talk to you about a cost benefit allocation process that can be utilized in an ISO/USO-type framework. You'll pardon me, I tend to use the term "ISO" more as opposed to unified system operator more; and I'll dive into my experience to explain why that is.

Here we go. That icon right there. Thank you so much. So really what I'd like to take the audience and the Commission through here is a -- just a brief discussion on the evolution of an ISO from the experience that I have had in North America and focus on how a cost benefit allocation or settlement process can work to identify the savings that can be related from a more economical dispatch pattern.

I'd like to start out just giving a brief history of the ISOs and where my experience has been with these ISOs, and then talk a little bit through an example on how a case study on the ERCOT market in Texas kind of evolved from a very simple ISO framework to a very more complex ISO framework.

When we get into these examples the intent is really to focus on the basic early ERCOT

model because I think that more relates to a model that the Railbelt would like to explore. And through these examples I hope to do a couple of things; number one, to try to show the ability to achieve these cost savings that have been identified in these studies; also to identify the process on how independently a system operator can financially allocate those revenues and costs appropriately.

There'll be a number of different assumptions within those examples, and I'll try to explain my assumptions as I go.

I'm not here to try to tell the Railbelt or the Railbelt parties how to run an ISO market; what I'm trying to do is utilize my experience to show you how I think it can work.

Okay. And just to touch on my background. I've been fortunate enough to have two really good, sound career paths around the ISO model.

I started out as an employee with the California ISO and with ERCOT helping arrange the settlement processes, which are essentially the accurate accounting of how energy transactions that -- took place in California and Texas.

After spending about seven years as a leader within the ISO world, I moved on to two private companies that essentially worked within ISO footprints in order to keep the ISOs honest. In other words, we operated very diversely, generation; retail business; we had a power marketing business; we represented renewable resources.

So we had the opportunity to ensure that the ISO was not only operate according to the rules for our assets and our customers, but they were also accounting for accurately the costs and revenues that we would assume that we could pass on to our customers.

I've worked -- primarily had a lot of experience with almost all of the Northern America ISOs, including a few in Canada. Most recently I left those private companies and started consulting for the ISO equivalent in Dublin, Ireland, that is EirGrid, as they are transitioning to a more integrated, single electric market.

They currently run a single electric market; they're looking to expand their reach into a more pan European market to include

additional options for them to buy and sell outside of the country. But the experience there in Ireland leads a good transition here to help consult on the Railbelt activity because it's a much smaller market, a 6,000 megawatt market.

Typically the other ISOs in North America have been large footprints, very complex commercial settlement rules.

So the experience back in Europe, I think, transitioned nicely to come here and talk to you all today about how this could work with the Railbelt.

So I think we're all familiar with the large footprints ISOs within North America. Really what I'd like to just point out is, no matter the complexity within the ISOs and the challenges that they have with some of their own infrastructure challenges, it's unique that almost each ISO is a unique entity in and of themselves.

They have a lot of shared operational and commercial financial rules that take place, but they all have certain differences amongst each other for the various constructs of their market footprint.

Some of these are all within one

state, such as ERCOT; some of them cross many State jurisdictions, including into Canada, like the Midcontinent ISO. We're not trying to look at the comparison of that to a Railbelt, but try and use some of the very basic principles that an ISO works that can benefit a potential Railbelt transition to an ISO.

And with that, I'd really like to focus my case study to you today on the evolution of ERCOT. Evolution of ERCOT really started in 1999 with the implementation of Senate Bill 7, which essentially mandated that Texas would have a competitive wholesale and retail electric market.

And this is what created the need for an ISO to form and be ready to launch a competitive market by 2001.

So there was a two-year, very tight time frame provided to the participants in Texas to do this.

Today's model's on the left-hand side of your screen there, it's the 2001 -- I'm sorry, the older model is the 2001 where we launched the market at its inception; and it was a much more simple market then what it is today.

The primary difference of the two

markets today is, you have regional pricing on the left-hand side; and more of a portfolio dispatch to where -- when you asked utilities to move their assets, a certain megawatt value was needed. And they could choose which assets they wanted to move. And you would assume they would do so on the most economic basis.

Today ERCOT actually now dispatches each unit individually based on the economics they submit. And they also price each of those units in a locational marginal price, or nodal pricing format.

So the primary difference you'll see is regional pricing to unit-specific pricing referenced on that graphic.

In the early model -- and I'd really like to transition my comments strictly to the early model because I think that is the model that best suits the Railbelt. I don't think there's really a need for regional pricing in the Railbelt. Potentially such a small network would only really need one type of indicative price for a market, whether that is a marginal cost market or even at a cost-based market.

And I'm not going to emphasize one

or the other, but I will probably talk about both. And I will, in my examples, focus on the marginal cost example. But I think these principles for cost allocation benefit really apply to either/or.

Likewise, the early days, the utilities were really skeptical about going into this competitive market under the ERCOT structure. And so a lot of these utilities were concerned about how they would operate and wanted to still operate it, to a large extent, the way they did in that day. They did not have a lot of experience, nor at first a lot of trust with the ISO framework.

So they wanted to ease into the operations by still doing what they had done in 2001, as opposed to providing all of their assets and meeting all of their obligations through the ISO.

The ISO would conduct a merit order dispatch. It would essentially try to find the most cost-effective assets available to meet the last incremental load; but this was also a security constraint-type dispatch as well, which is why they had to perform some out-of-merit or non-economic commitment to units to ensure that

the grid was reliable.

Primarily this was done to help manage transmission congestion constraints. But it can -- could include providing voltage support in areas that required it or even having must-run capabilities available for areas that were short on capacity and that required that reserve there specifically to meet any swings in load forecast.

Likewise, a reserves market was established. The ability to provide regulation service, which is critical to the ISO to ensure that they can manage system frequency; but also providing spinning and non-spinning reserves that would respond either more quickly or less quickly than others, but still had a value to the ISO and to the market so that they could provide a near instantaneous response to when you had swings in demand that required additional capacity to be either generated or to be curtailed.

And finally, the early model also had a significant presence from the Public Utility Commission from a regulatory basis. They primarily set the stage for ERCOT to form an ISO by assigning a postage stamp rate process to the transmission cost; kept the transmission business

and the assets within the transmission owners, but ensured that the transmission owners would be able to get the rate of their return necessary through regulatory rate cases. Essentially keeping the transmission aspect of Texas regulated.

The reason to select this model -- and I think that it's almost every ISO that has evolved has kind of started out with something very much more simple than what -- the way it evolved to today.

And the key point on this evolution summary that I have before you really is the fourth bullet down that I'd like to kind of elaborate on.

When ERCOT started this initial model and -- from 2001 and operated that way until 2010, the ISO themselves really only balanced approximately five percent of all the transactions within ERCOT. In other words, all of the utilities were either self-supplying or bilaterally trading with themselves in order to meet their demand obligations.

So the ERCOT market essentially became more of a balancing pool, if you will; but trying to use the economic dispatch in those

situations in order to ensure that the last incremental load was met and appropriate reserves were on the system.

The evolution of ERCOT, it also was something that was extremely stakeholder driven; the last bullet.

As an ISO, and with "I" being the appropriate letter there in that acronym, we were an independent entity that essentially assisted or facilitated the crafting of the rules, starting in 1999 up until market implementation of 2001.

Every market participant's segment was represented; all utilities from the investor-owned utilities to the independent power producers that were now coming into the Texas region to new retail providers that wanted to come in and market their business to areas where retail customers were allowed retail choice.

Every segment was remitted within that framework and literally would gather in conference rooms on a weekly basis and put pen to paper to get these rules in place that the ISO would follow and that the market participants would follow. And that's what we defined as a stakeholder process.

So the ISO truly was independent in facilitating a market that was written by market participants for market participants.

So my expertise really is on the financial side, or the commercial side, as I like to call it. We've spent many years in looking at many different -- what I call settlement methodologies.

And to me, settlement is the same thing as trying to find out the cost benefit allocation for revenues and cost within an energy ISO footprint or any kind of a competitive market footprint. Competitive markets or cost-based markets still have the ability to find efficiencies in revenues and costs.

So when I look at drafting rules and looking at algorithms for these equations that are supposed to follow the rules in -- and allocate these revenues and costs accordingly, whether this is cost based or profit based, to me doesn't matter. The inputs are what the inputs are.

The economics from the participants, the obligations and the supply obligations from the market participants in

basically trying to determine what a participant tell us -- tells us they're going to do in a forward period and then what they actually do in realtime; and then allocating the costs and revenues accordingly.

If doing so under an economic dispatch process -- what this gives the opportunity to do as an ISO is to significantly reduce fuel and purchase power costs by selecting the most economic resources possible. And that, to me, is something that can benefit all market participants within the grid.

The concern there is for investment in less economic units that takes place and the ability for those participants to earn their rate of return. Somehow there has to be a mechanism in place potentially to allow that to happen as well.

But, again, the focus on cost benefit allocation, and a process in and of itself, works very fluidly with either a cost based/cost savings market or a competitive market. I do not try to delineate between the two.

So I'm going to go ahead and get into a couple examples. And the examples are really going to have the same scenario just to

show how the cost benefit allocation process works and to show at a high level and focusing solely on an energy transaction. So this is not comprehensive of all of the potential settlement activity or cost benefit activities that would take place, but I will mention that they're looking at the Railbelt in and of itself.

There does not seem to be a significant number of areas to consider for cost benefit allocation. Energy would be one of the primary ones, because that's where you're most -- the most savings is probably going to be accrued from your -- a reduction in purchase power and fuel costs.

However, we will, in a document that I intend to present at some point in completed form -- will talk about how reserves can be settled; how mustering units can be settled. And then as -- very basic discussion on unit commitment as well for situations when there's just a need for a locational unit to be online and available.

But our focus on this example is really to look at energy and to talk about how the ERCOT model -- using the ERCOT model, how you can

see a cost savings from an economic dispatch.

The example, if you will -- if you'll look on the screen -- there are basically going to be three utilities. Each utility, in and of itself, has a demand obligation; a load forecast that they have to meet, and they have supply that they can either self-supply or they can offer at their cost into the ISO framework.

In the example, Utility A is actually going to self-supply a majority of its demand obligation; and it's also going to make a purchase from Utility C to meet the remaining part of its demand obligation. Utility B will come into this example; and all they'll want to do is self-supply their demand obligation, but they have additional capacity that they'll offer to the ISO at its cost.

And Utility C, as I mentioned, has already sale -- sale to Utility A; but they also have a demand obligation that they will meet through a very efficient resource of their own in its entirety.

The next four terms that you see on the slide there are actually terms that I've made up; and I've made these up for a reason, because

when you start thinking about drafting rules for a settlement cost --

CHAIRMAN PICKETT: Excuse me just a -- would all of you online please mute your phone? You're disrupting the proceedings. Please mute your phone. We'll try to proceed.

MR. GALVIN: Thank you. So, again, these four terms are really made-up terms for the purpose of this example; but they also would be a starting point for defining settlement charge codes or cost allocation charge codes required.

CHAIRMAN PICKETT: Excuse me, I hate to interrupt you one more time; but would all of you online please mute your phone. Please proceed, Mr. Galvin.

MR. GALVIN: Thank you, very much. So the energy balancing resource in this case is going to be a calculation that allows for a final cost or revenue determination based on metered generation, whether that's over or under the supply obligation that the resource has.

CHAIRMAN PICKETT: Again, is there any way we can selectively figure out who this is and disconnect them?

COMMISSIONER McALPINE: Disconnect

everybody and have them call back. She's not listening to you, so obviously she won't call back.

CHAIRMAN PICKETT: Again, for the -- would all of you online please mute your phone. Thank you.

MR. GALVIN: Thank you. So energy balancing resource will represent a calculation that simply looks at, what was my supply obligation as a utility; and what was my metered generation against that supply? And it'll be calculated at an assigned price.

Energy balancing demand is the same thing for the load side, any metered load over or under forecast at a price will calculate a cost or a revenue for that utility. And then the two components that are needed for that calculation are supply obligation and demand obligation, and they're very simple.

On the demand obligation side the sum of what the utility says it will self-supply, as well as what it may purchase from another utility. And the supply obligation represents what a utility will self-supply from its own generation, as well as anything it sells to

another utility. So these are just setting up the basic parameters needed for a cost benefit allocation calculation for the example.

And now I apologize for testing your eyesight on this, but let me do the best I can. I'm going to use the pointer here as well, so hopefully I can -- if you'll direct your attention to the screen, I think I can explain this with the help of this laser pointer a little bit better.

So Utility A we'll start with. As I mentioned, they have a self-supply of 50 megawatts from two resources that they have. And as you can see, for the simplicity of this example, we're going to keep the cost as a flat dollar amount, as opposed to using incremental costs. But, again, just to keep this example simple and demonstrate the process, we'll just look at flat cost for each generating asset.

So they're self-supplying 50 megawatts of their own load obligation, and they're purchasing 25 megawatts on a purchase from Utility C. So their final demand obligation, what we expect them to take from their load forecast is 75 megawatts. But we expect a supply from their

generating assets of 50 megawatts, and we'll make sure that we'll account for this accordingly once we see what their metered generation and metered load is.

Utility B in this example has a self-supply of 100 to meet its demand schedule of 100. Their units are a little more efficient and they've provided equal generation from both assets; but they also have additional capacity that they can offer to the ISO at those units, just like Utility A does with their additional capacity as well.

Utility C has the two most efficient units; it's self-supplying its demand obligation of 200 megawatts from its most efficient unit, and it's selling 25 megawatts to Utility A in this example. So we expect from a supply obligation from their assets to get 225 megawatts of generation, and we expect their demand on their load forecast to be 200.

So we can automatically create a stack, if you will -- an economic stack of generation that goes from the lowest cost generation to the highest cost generation, and this provides the ISO with the amount of energy

required necessarily -- necessary to balance any changes in load forecast or any unforeseen conditions.

Units six and five, unfortunately do not have any capacity because they're fully committed; so the most efficient unit that the ISO can choose from in this stack starts at generator four at a $70 unit.

Okay. So in realtime, two things happen; we see that Utility A's efficient unit, generator five, the $40 cost unit, actually trips; so it is now not available to provide its 25 megawatts, even though this was a sale that they had to Utility A. Likewise, Utility C also has a 10 megawatt forecast error.

So currently the ISO has to balance the system now with a 25 megawatt trip and a 10 megawatt forecast error or it requires an additional 35 megawatts of capacity to put to the grid.

The capacity that was available was 25 megawatts from generator four at $70; so they'll take the first 25 megawatts from generator four, and generator three then provides the final 10 megawatts at $80.

In ERCOT this would essentially, in 2001, set a marginal price of $80. A system marginal price, really by definition, is just that last increment of generation used to meet that last increment of load on the system. So that $80 would set the price -- system marginal price for this particular period.

To calculate the actual cost benefit allocation for this, let's start out with Utility A.

Utility A basically had their purchase of 25 megawatts at the $40 price from Utility C. Even though at this point Utility C was unable to deliver that, that is still a cost that they have for that transaction that took place forward.

But their energy balancing resource and energy balancing demand, they have no exposure to the system marginal price. And the reason being is they told us that they were going to deliver 50 megawatts, and they did.

On the supply -- on the demand side, they told us they were going to have a load forecast of 75 megawatts; and they met that with their metered load.

So the true cost here for Utility A is that -- the thousand dollars cost on the purchase from Utility C; but also the cost to self-serve its own load with those higher cost units, one and two, which were a hundred and $120 respectively.

For Utility B, Utility B was actually dispatched by the ISO because they had the most efficient generation. Now, granted, they were following their own load for the majority of that generation. So all the ISO's concerned about is that 35 megawatts is dispatched in and above what they were self-supplying.

So, again, they told us they were going to supply, one, their own load; but they also had an ISO dispatch of 35. They're paid that at the system marginal price of $80.

On their energy balancing demand side, there is no exposure because they met their load forecast as they told us what their forecast would be.

And finally, Utility C still has the sale to Utility A. Even at this point we know they were not able to deliver that sale, but they still have that revenue stream of a thousand

dollar sale to Utility A that took place in the forward.

However, because they are short 25 megawatts to what they told us they were going to supply, they're actually essentially replacing that power at the system marginal cost of $80. So they're carrying a $2,000 expense.

And likewise, because they did not meet their load forecast, they were 10 megawatts short, they also are purchasing that 10 megawatts from the same system marginal cost at $80 for a net cost allocation of $1,800 in this example.

The simplest summation of all three of these transactions equals zero, so the ISO remains revenue neutral. And this allows all the utilities to still self-supply, only be subject to the incremental balancing, and allow for the market to be balanced when system conditions and low forecast error take place. This is how ERCOT would have operated in 2001 to 2010.

The next example, taking the same format, what I'm going to do is try to take you to the full other end of the spectrum and look at what a hundred percent economic dispatch would have looked like in that scenario.

So the assumptions we're going to use for that example are basically 100 percent of the generation from Utility A, B, and C is going to be offered into the ISO at cost; there are no purchase or sale transactions, nor are there going to be any self-supply transactions. We're going to look at 100 percent dispatched economically.

The system load is going to remain at 385 megawatts. So we still have the load forecast that tells us it was at 375; but when actual metered load comes in, the ISO is still going to balance to the 385 megawatt market. And then the US -- or the ISO rural dispatch, all these generator offers essentially to meet that incrementive demand.

So, again, going back to the same grid, there now is no supply or demand obligation of note. Everything is going to be cleared through the ISO. The ISO still needs to balance the grid and set a system marginal price.

A hundred percent of the generation bid into the market -- or into this cost-based market would include now the ability for us to dispatch 200 megawatts from generator six because they are the most efficient unit on the bid stack;

75 from generator four because it's the next most cost effective -- remember, generator five is tripped; so it's not available at $40 -- and generator three then is finally dispatched, so 110 of its 200 megawatt capacity. And, again, in this example we set a marginal price just like we did in the first example of $80.

Now, the actual settlement changes a little bit between party; but let's look at it a little bit more closely.

First of all, there is no purchase or sale. So they do not have the sale for Utility A from -- to Utility C, so there's no expense there. Utility's A resources are now non-economic and not operating in this particular period.

So there's no energy balancing resource or subject to that cost -- or I'm sorry, to that revenue. A hundred percent of their demand, 75 megawatt of demand is now costed at the system marginal cost of $80 for a net expense of $6,000.

Now, if we recall in the first example, they were self-supplying their load with much more non-economic units. And in this example, they've actually purchased and satisfied

their load obligation from a more cost-effective, more economic dispatch pattern and served their load at a lower cost.

Utility B, who has the two units dispatched at 110 and 175 megawatts has 185 megawatts now settled at the $80 marginal price. And as you recall, one of those units was only a $70 unit.

Again, this is how ERCOT would have used a system marginal price as their settlement methodology. It's quite possible that you could still do the same cost allocation by simply paying each of those generators at their cost level.

But for the purposes of this example, I still want to focus on the ERCOT model; and then we'll talk a little bit about cost based versus marginal base in a few minutes.

Likewise, a hundred percent of their load is now met at the $80 system marginal price. So they have a net revenue stream now from the assets generating at $80 and the load being charged at $80, a $6,800 net revenue.

For Utility C, even though the unit is tripped, they still have provided 200 megawatts of generation.

Again, in this day, ERCOT would have settled them at the system marginal price of $80, even though it was a $30 unit. And likewise, they also have an energy balancing demand of a hundred percent of their load, including their forecast error of 10 megawatts at $80 for a net revenue and cost summation of negative $800.

So we still see that the ISO remains revenue neutral in the cost allocation. And while these numbers are different, we can start looking at overall operating costs and look at each utility and see how they were impacted by the traditional older model of self-supplying and self-arranging versus the hundred percent economic bid.

So this -- this just simply represents what the operating costs were, again, assuming that the generator costs used in the example are their operating costs. And for the purposes of this example, we're strictly talking about variable O&M and fuel.

Generator one, two, three, four, and five and so on, they have operated at the certain level that they did for a net cost of 21,550. But when economically dispatched, these

units actually operated at a cost of $20,050 for a savings of $1,500 in the example.

So this shows how that -- cost benefit studies that have been done on how economic dispatch can actually provide savings related to -- primarily around the areas of fuel and purchased power expenses for the benefit of this ISO footprint.

Now, let's talk back about the fact of a marginal cost market structure versus a cost-based structure market.

If we decided to operate under a cost-based structure and each of these assets were only compensated at their operating costs and they had the ability somehow to recover their fixed costs and other means, there is a -- the opportunity to increase the savings even more because generators -- three would be essentially not paid at the $80; but they would be paid at their $30 cost. Gen -- the other -- I'm sorry, that was generator six that was the most efficient.

This is, again, where the difference between a cost-based market and a marginal pricing market exist.

Why ERCOT would go to a marginal price market is very simple in that -- the fact that a lot of independent power producers are now coming into the market; and as opposed to the utilities who have the ability to recover their fixed cost through their retail tariffs, independent power producers do not have that opportunity.

So a marginal cost-based structure probably provides the benefit of providing additional price incentives for a future investment. However, it does not optimize the true savings that you can have from a cost-based market.

From my perspective on how you build settlement algorithms or cost benefit allocation algorithms around either of those, either one can take place.

I'm not going to tell you which one is better than the others; I think they're -- just the physical math around both of those components can take place. And the market stakeholders can determine the method necessary to approach how they want to tap into that savings that can be recognized through economic dispatch.

I want to quickly also take you through each of the utilities' differences in the two examples just to show you what their position would be in both scenarios.

So, again, Utility A had the ability to self-arrange their own demand obligation, but also purchase from another utility.

So in example one their operating cost was the operations of generator one and two at their cost of 100 and $120. And likewise, they had the purchase from Utility C, which was an efficient purchase in this example; and they had no exposure to the system marginal price because they met their load forecast and they met their supply obligation.

So in the first example, they had a net cost operationally of 6,500 negative; whereas in example B, by purchasing all from the system marginal price, they actually saved $500 in this scenario.

Utility B, which came into this with the intent to completely self-supply its own load forecast, now is operating their units differently.

So in the first example they were providing 135 megawatts of generation, so their operating cost at each of the two units would be reflected here; plus they had the balancing amount that they provided to the ISO of an additional 35 at the system marginal price of $80 for a net of $7,250 negative.

When we look at the second scenario, their operating costs actually increased. But they're actually receiving some revenue over their cost from one of the units; and they're meeting their load at or near the price that they had intended to by self-supplying, so they're unharmed in the example. They have the same result in both cases.

And the third utility, Utility C, in the first example they had to replace the unit tripped power because they told us theirself [sic] their supply obligation was going to be 225; and they also have the load forecast error of 10 megawatts.

They had the sale to Utility A, and they also had generator six operating at a cost of $30 for a net cost of $7,800 in the example one. In the example two, they provided the generation

at 200 at a cost of $6,000; they had exposure to the system marginal price for their resource and for their demand obligation for a net of $6,800.

Now, the cost that's not showing up on here for Utility C is the opportunity cost they would have had to be able to provide that additional 25 megawatts of generation at a very efficient cost of $40 by being compensated at an $80 rate.

So the trip still does impact Utility C; but still even in an economic dispatch world, they come off better if it's fully economically dispatched.

Now, again, to caveat the examples that I've provided, they were done so for two reasons; really to show you how ERCOT had started in the first day.

A utility is very concerned about getting into this new competitive market framework, not necessarily wanting to change the way they operate. They were still self-supplying and self-trading; and they were able to meet their necessary obligations internally or through their counterparties, but still have the ISO there to economically benefit them or balance when needed.

All the way to the other end of the spectrum, we have a hundred percent economic dispatch.

I will say that most ISOs eventually gravitate towards 100 percent economic dispatch, but they never really get there entirely because that is the security constrained aspect of the dispatch that takes place. In other words, the ISO does have to utilize non-economic units at certain times.

And I think you can possibly imagine the scenarios even for the Railbelt where some non-economic units at least have to be either online and available at their minimal load, or they may have to be generating at a certain level in order to be there and available in case of a system contingency.

So getting to a hundred percent economic dispatch may not ever happen because of the security constraint commitment process, but there is still a range of economic savings to get to as we move more closer to that economic dispatch. And that's what I've seen financially take place working both for the ISO and working for utilities that have to participate within an ISO.

The appendix, I have a variety of different slides that provide some different -- additional information. I always hate bringing up the mathematical aspects of it; sometimes I do it just to try to impress people, other times I just try to do it to cause additional headaches of some of the headaches I've experienced in my experiences with the ISO.

I'm actually working on a straw-man documents that I'd like to at least have presented to Railbelt utilities to see exactly how a settlement cost benefit allocation would work, whether it's using a marginal cost-based pricing method or whether it's using just a simple unit cost-based method.

Both of those activities would be reflected in that document. And it will contain some of the detail, like some suggested mathematical examples that can be utilized to -- really as a starting point that if we see the Railbelt go down the path of creating an ISO framework, that the straw-man document provides a good point to at least craft tariff rules with the stakeholders doing that in order to establish some of the things that can be used to implement an ISO

and a cost benefit structure within that ISO.

And with that, I'll take any of your questions that you might have.

CHAIRMAN PICKETT: Commissioner questions at this point from -- Commissioner McAlpine, any questions? Commissioner Wilson? Commissioner Patch, do you have any questions online? Commissioner Rokeberg, Commissioner Patch, are you with us?

COMMISSIONER ROKEBERG: Yes, can you hear us now?

CHAIRMAN PICKETT: Yes. Do you have any comments or questions of Mr. Galvin?

COMMISSIONER ROKEBERG: No, not at this time. And thank you very much.

CHAIRMAN PICKETT: I have some questions. Going back to the 2000/2001 era of ERCOT, can you -- and I've had conversations with members of the Texas PUC, but they weren't there at the time -- so can you help me understand the role of the PUC in Texas as this whole process -- was it focused primarily on transmission; or what --

MR. GALVIN: The legislative Senate bill, Senate Bill 7, really was the -- was the

whip, if you will, that got the whole process started. And there are really four pillars that were required within that Senate bill.

And I can summarize them by saying that the first opportunity was to provide open access, both to new entities; to new retailers; to provide access to the assets in a -- in providing new investment within the grid in order to facilitate a competitive market.

The other pillar was to provide retail competition. And, you know, ERCOT is a hundred percent -- oh, not a hundred percent competitive, but is majority competitive.

The non-opt-in utilities and municipalities and cooperatives had the ability to opt in to competition; only one of them did. So they are keeping their customer base, but they were able to opt in to wholesale competition so that those public power entities could provide for their own customer bases different opportunities to meet their obligations, as well as marketing their assets to ERCOT as needed.

The third pillar essentially was to ensure reliability, to ensure the reliability of the grid -- it's what the ISO primary

responsibility was; but you cannot have an open access and kind of a free-rein market without the ability to ensure that the assets of the grid and the ability to transmit energy effectively and efficiently but also safely was conducted.

And finally, there was the accurate accounting of that activity was the fourth pillar. The ISO, under a framework to create the independence to operate and facilitate that type of market, needed a regulatory body in order to do that.

And the Public Utility Commission's role, indeed was that. They had the regulatory oversight; they also did much of the early monitoring of the market until later on it was determined that they would be better served by having an independent market monitor that would be implemented into the ISO framework.

The Utility Commission would set a framework of support to and over and above the governance structure that the ERCOT stakeholders laid out.

So the ERCOT stakeholders would essentially draft the rules; they would have to be approved and verified by the Commission. And the

governance board essentially would be able to handle all disputes or activities that were not agreed upon within that process; and if there was no agreement that could be made through the governance structure, the PUC had to be there to allow for open cases to hear those and to help make decisions on those.

We've had a vast number of commissioners from 2001 to 2015, many of which I would say were -- started out as not being as savvy about ERCOT and the markets; but they became so quickly because of their responsibility.

But the governance structure in place allowed a stakeholder board; and in due time, there were independent board members also added to that to really handle a majority of the issues that took place, while the PUC would still have the oversight and still be a last resort for those kind of issues to be resolved.

And finally on the area of transmission, the ability for the transmission system to still remain with the transmission owners and the owners still have the ability to achieve a regulated rate of return through a regulated process enabled the separation of

transmission from the ability to conduct open-market activities for ERCOT.

Providing that structure on the transmission side was essential to allowing that separation to where the assets remained where they did; and those asset owners had the opportunities to get their investment costs recovered, but that they would also have a secure relationship with the ISO so that their assets were essentially monitored and operated on reliability.

So setting that structure, separating the two, but keeping the transmission and the ISO as close -- closely knit based on the market operating rules as necessary and having the transmission owners a seat on that governance structure still provided that connection between the ISO and the transmission owners.

CHAIRMAN PICKETT: I found your presentation to be helpful. Over the last year I've spent quite a bit of time studying ERCOT, been to Texas a couple of times and kind of looking at the current state; and my takeaway was, this is way too much.

Not that we can't learn from some of the elements of it; but there is an incredible

level of complexity, particularly for a very small marketplace that is not a restructured market. And we have no IOUs; and we have basically co-ops and a municipality and a small municipality, so --

MR. GALVIN: But you also have a lot of potential in future --

CHAIRMAN PICKETT: I agree.

MR. GALVIN: -- in reducing fuel and purchase power costs. And, you know, there are ways that can -- that can be done. And the best -- you know, the complexity that I continue to see in Texas now as a resident of Texas -- and it was about eight months ago when I left the private companies --

CHAIRMAN PICKETT: Uh-huh.

MR. GALVIN: -- to where I stopped badgering the ISO about how we were settling financially with our company and ensuring that they were accurately accounting for our business -- going back to the Ireland project, I see a vast similarity there between what they're doing; the complexity of interconnecting with a market structure with other European nations when really they have the ability to conduct their own business as they'd like to within the country.

But it's also a smaller grid; it doesn't need the complexity of Texas. It does need the same principles though that the ISO really stands for; and that is some sort of independent body that can facilitate, you know, a fair and balanced operational aspect of the market based on the market rules that are provided.

CHAIRMAN PICKETT: Uh-huh.

MR. GALVIN: And I think that is really where my focus is. I don't think you would -- there are -- I -- the settlement world, I can tell you, that there are over 60 different types of transactional charges or credits.

If you could picture your credit card statement having a line item of each one of those on a daily basis, that's what ERCOT does. That's not needed here. Not -- that complexity is not needed here.

But the ability to allocate that cost benefit that is there in the studies on revenue and fuel purchase power, the more accurate that can be done and the best auditing processes around that, I think can help the Railbelt as a whole.

CHAIRMAN PICKETT: Uh-huh. And is

it fair looking at the history of the development of ERCOT to say that SB7, passed by the Texas Legislature, was a pretty critical piece of that; and how did that actually -- what was propelling it? And the industry --

MR. GALVIN: Yeah.

CHAIRMAN PICKETT: -- government, how did it come into being?

MR. GALVIN: Well, it was the incentive that was needed to get something different. Without the legislative mandate -- you've had discussions on power pools and you've had power pool-type sharing; thoughts that were being discussed; various ways that ERCOT could help manage -- really what ERCOT was prior to what it is today, was 10 unique control areas with the utilities embedded within each control area. And ERCOT was managing the flow from control area to control area.

So there were -- be talks of how they could more efficiently do that and how they could better look for the economics; but you still had embedded each -- within each of those control areas interests and issues and concerns that those utilities were, you know, quite determined to

maintain.

So those discussions and negotiations could have gone on and on for ages without the Senate bill. The Senate bill basically said, you will implement this. And they gave them two years, and we implemented it successfully in the month we intended to in July of 2001. So it was very critical to doing that.

Now, what it created was the requirement for the stakeholders to come together and get these rules drafted that they would operate under, with the help of the ISO. And in -- that's when I joined ERCOT, it was when that process actually started.

We literally started occupying conference rooms and then eventually ballrooms at hotels to sit down on -- with a video display and literally write out the rules for the market structure.

The ISO there with the voice of reliability, but the market participants there with the voices of how they wanted their market to work. And that required getting them -- some of their brightest people, the folks who knew the grid there, who knew the participants, to

negotiate with each other.

Something similar probably would have to happen here. You would want your stakeholders to have their folks who know their businesses, as well as the business of others, getting into a room and discussing what those rules should be.

CHAIRMAN PICKETT: Uh-huh. But obviously there was some critical mass in the Texas Legislature and the Governor's office at that time that supported it because of either concerns with reliability or economics generally, I don't know what was --

MR. GALVIN: Primarily around retail -- opening up retail competition and retail choice.

It's only recently that -- there's always been issues around a system like ERCOT, which is 68,000-plus megawatts at peak; and with very predictive weather patterns over the course of a year, you know when your peak seasons are. And so we're very cautious about what our reserve margin is in Texas.

But the reserve margin has always been pretty robust in the early days; only

recently have there been older units that are starting to come offline.

Opening up access to retail competition, retail choice was one of the -- the primary pillars of Senate Bill 7. The ability for households, smaller businesses, large industrials, really to have a say in what their costs at their household would be.

That scenario really would not exist in the Railbelt, but it's -- it was the primary impetus for creating the Senate bill; and therefore, a competitive market structure that would allow the facilitation of that.

It's from that Senate bill that also thought -- or the birth of a wholesale market to help support the reduction of costs to the retailers would work well with that.

CHAIRMAN PICKETT: And it sounds like a critical ingredient was the rationalization of the transmission system to where you didn't have balkanized pieces and you had some predictability on transmission tariffs across --

MR. GALVIN: Yeah, the certainty around the transmission framework as laid out prior to going live with an ERCOT market as we did

was essential.

CHAIRMAN PICKETT: Thank you. That's all I have. Any further Commissioner questions at all? Commissioner Patch, do you have anything; or, Commissioner Rokeberg?

COMMISSIONER PATCH: No, thank you very much, Mr. Pickett, I appreciate the opportunity. I appreciate the presentation.

CHAIRMAN PICKETT: Again --

COMMISSIONER ROKEBERG: Yes, thank you.

CHAIRMAN PICKETT: -- thank you very much. Your presentation was very helpful. And with that, we will close agenda item number three. And we'll take a short 10-minute break and allow our next presenter to get set up.

MR. GALVIN: Thank you all very much.

(Off record.)

CHAIRMAN PICKETT: We are back on the record; it is approximately 10:08 a.m. We are now on agenda item number four, Presentation: Municipal Light & Power - Centralized Power Pool/Economic Dispatch Services with Mr. James Trent and David LeVee.

And I will turn it over to Mr. Trent for any further introductions and tee it up.

MR. TRENT: Commissioner Pickett, thank you very much for allowing --

CHAIRMAN PICKETT: Please hit the green light on your microphone.

MR. TRENT: It is.

MR. LeVEE: It is there.

MR. TRENT: Are we live? Is that better? Thank you, Commissioner Pickett. We're interested in talking to this group to let everybody know what ML&P thinks about what's going on in the Railbelt.

We're very interested in all of the proposals. We're eagerly discussing the aspects of ISO, USO, TRANSCO, energy process, everything that's going on.

Sadly at this stage we are unable to make a good business case for any one of these proposals, and we are deliberately looking at every aspect of these things.

What we've discovered, however -- and, of course, of every proposal, without any exception, there is embedded a process entitled

economic dispatch power pool. There is no exception to that comment. Every proposal has that embedded someplace in it. Your consultant last week suggested that that was also in his evaluation.

We've decided that some years ago at ML&P we began to do economic dispatch for our own personal benefit. And let me turn on this thing here. All right. Is this working?

And in the beginning at ML&P we used this software called PUFFIN. And we discovered some months ago that PUFFIN was outdated; we couldn't upgrade it in way, shape, or form.

And as we began to look at what we were doing in terms of economic dispatch, we thought we could apply that same economic principle to the Railbelt in its entirety without exception. But we discovered that PUFFIN was not up to the task, so we decided to look for an upgrade in PUFFIN.

And we sent a team to the Lower 48 to find out what was being used down there. We discovered a program called AURORA.

We discovered that AURORA was a

day-ahead process that allowed us to -- unrestricted, get involved in economic power dispatch across the Railbelt.

AURORA's being successfully used today throughout the Lower 48 and into Europe. A number of people are using AURORA to be involved in economic dispatch -- Power Association, for example, is adopting AURORA for its process. We discovered that at NASA and the Boeing Company were using AURORA in their own minds to make sure they selected the right equipment.

In the case -- AURORA is a proven software that allows day-ahead economic dispatch and power pooling.

So we brought PUFFIN into -- AURORA into ML&P and have been using it to establish a database upon which we can supply the Railbelt for day-ahead economic dispatch functions.

We put together a proposal and have concurrence from four out of five of the utility companies throughout the entire Railbelt to engage in a one-year no-cost program allowing ML&P to provide economic dispatch and power pool activities across the entire Railbelt; not just for MEA, not just for HEA; but for all of the

utility companies involved, with the exception of one.

So we have four out of five utilities in agreement for the first time in the Railbelt history, I may say, to use a common process, which is the AURORA process in terms of economic dispatch throughout the entire Railbelt. That process is in motion now.

We are compiling the database requirements necessary to engage economic dispatch in its purest form for every machine, without exception, in the entire Railbelt.

The gentleman on my left is Mr. Dave LeVee, who is the original programmer for AURORA, who will now take us through some of the aspects of the AURORA software itself. How do we get to RCA?

MR. LeVEE: Good question.

MR. TRENT: You bring up your thing.

MR. LeVEE: I'm not sure which one it is on there. Probably the RCA --

MR. TRENT: It is.

MR. LeVEE: -- presentation at the bottom.

MR. TRENT: Yeah.

MR. LeVEE: I will use the -- this method here.

COMMISSIONER ROKEBERG: Mr. Chairman, we're having difficulty hearing the presentation.

CHAIRMAN PICKETT: Yes, we'll have them speak directly into the microphone and make sure that it is on.

MR. LeVEE: Okay. I'm checking to make sure it's on; I hear my voice echoing in the background.

Again, my name's Dave LeVee, and have a history with AURORA. From its inception was one of the initial developers providing kind of the economic foundation and fundamentals in the AURORA economic dispatch model. So certainly very familiar; used that in my services to do consulting and forecasting, as well as economic dispatch and analysis of positions taken in that market. So I'm very familiar with the tool.

So that's -- the purpose of the presentation today is to describe to you, I guess, those capabilities that are within AURORA. And whether it is the absolute best tool or not the

best tool is not something that I'm going to evaluate and consider, but I will say that -- very strongly that it has the capabilities and has a lot of attributes that I think is in line with your needs.

So AURORA's strengths. One to say -- user-friendly. I mean, that's a nice buzzword. User-friendly allows basically full transparency and intractability with the model. So basically it's a tool; it's certainly not a black box, but it's a tool that's based upon a framework that has a transparency in the data and information.

So you can stop the model, you can look at results, you can look at what is actually happening from an economic dispatch standpoint. It gives you full transparency and capability to look at number -- or basically all the detail that's going on in the tool.

So, you know, if I was to say that's the one biggest, single strength of the tool, not only is its capability but its transparency and ability to understand what's going on in the tool to do manipulation of data and information that comes from the tool.

With that comes the ability to generate a -- numerous kind of reports, some of those are built directly into the tool. Just with the push of a button you can do any number of reports that you can customize and extract that data and information to produce any number of reports from the tool. So, again, it gives you a full transparency. It has a proven record.

I'm not sure how many clients -- I don't currently work for EPIS; I am my own consultant, and I use AURORA for that -- these types of forecasting purposes -- but they have an extensive number of clients, both within the United States, Canada, and internationally in other markets.

And in terms of support, speaking to my former associate and developer of the tool, that was our number-one key thing that we were going to establish our name on was support.

So you'd find that the model is very well supported; and basically the team allows for input -- you know, requests input from users and makes adjustments and changes to the tool. So the -- basically, again, very user-friendly; but also very adaptive.

Conceptual overview, it's an economic dispatch tool that simulates basically the actual operations of resources; looking basically up the dispatch stack from lowest cost to highest cost to fulfill hourly demands. Demands are basically part of that stack.

In some cases you may have curtailment of load. So as mentioned, I think in a previous -- the previous presentation, demand is also part of that pricing algorithm.

So you determine prices based upon both supply options, as well as demand options, if they exist.

Transmission paths are basically costs; costs are included to include the wheeling cost, as well as losses between areas or regions in the model and becomes part of that dispatch algorithm.

So as -- it's looking basically at the cost of -- in that dispatch stack, it counts for resources that are across transmission lines and the associated costs for those dispatches.

So, again, it does an economic consideration inclusive of all the costs, including transmission. It provides an accurate

simulation of those resources; that includes complex resources that have runtime constraints, minimum runtimes, maximum runtimes, ramp rates, other things that are specific to those individual units.

Again, the simulation is highly refined so that it can model and accurately model the resource operations, given those constraints. So there's a lot of detail and capability within the tool.

Again, getting back to AURORA having a number of clients and being used extensively in -- by a lot of companies for this type of purpose.

You know, it has a lot of things added in and capabilities that have been developed within the tool because of the exposure that it has.

Topography, basically that's -- that's a -- it sounds somewhat physical -- the physical capability is to say that you're looking at the electrical interconnections of all loads and resources and also the distance and transmission costs associated with those. So topography is kind of the electrical connection,

if you will.

So you can easily identify and formulate to make sure that you have an accurate representation of that Intertie capability of interconnected loads and resources.

So that -- that's part of the exercise when you go through and validate to make sure you have the right framework so that you have economic dispatch occurring properly based upon the right parameters and the right economic incentives.

Resource operations and constraints, again, you have minimum uptime; downtime; start-up costs; ramp rates. That's kind of a -- a beginning list of a long list of the types of operating constraints that you can include in AURORA.

So it identifies and looks at and considers when it makes decisions about what our resource costs are and what those incremental costs will be. Again, highly transparent.

So you can look at a particular resource, its operation, when it turns on, what the price was that it turns on at; all that information is very transparent in the tool. So

it gives you that capability to refine and fine-tune, if you will, to make sure that the resource -- excuse me, that the model is simulating the actual dispatch.

Commitment logic looks at resources that, again, with minimum runtime operations, have to commit for dispatch looking at their economic value over their dispatch period. So it assures basically that those units that -- look forward and say that they have to operate for a certain number of hours at different levels.

You know, some of those hours may be operations that have negative value; but because they're committed for that time period, they minimize the period in which they're losing money from a market clearing price perspective, I guess, or economic value. And then will ramp back up to their full potential, given the situation where they have positive value.

So it looks at all those values, and then it'll make decisions about commitment based upon the accumulation of those values. And once they are committed, then it will look -- and look at its options; minimum uptime, minimum downtime; and make decisions about whether that --

you know, it continues its operation.

Again, transmission includes wheeling charges, as well as losses between areas. The wheeling charges are input to the tool, and you can specify down to very refined and small levels of detail; you can have hourly transmission prices. It's -- again, it's user defined.

You can put in whatever assumptions you think are appropriate into the tool and use that in doing its economic dispatch.

So it gives you the optionality, if you will, to say what if you had on-peak prices different than off-peak prices, for example; or you wanted to look at kind of a market-based rate for transmission. I mean, you can specify what you want it to be.

So it gives you a lot of capability for analysis as well to make decisions about what is the best use, for example, of transmission.

Losses are accounted for a couple of different ways. One, losses constitute a loss of energy. So if you have losses on your transmission line, you have more resource generation to accommodate for the losses, as well as the loads that you're serving.

In addition to that, you have a -- as it's transferring across the transmission line with losses, the effective cost because of the kilowatt hours delivered is the price with less kilowatt hours delivered; so you have an increase in price as a result of losses.

Okay. You can include inputs specified to reflect transmission loading. I -- with I-squared-R losses, for example, they aren't necessarily linear; you can adjust and have transmission losses in prices corresponding to the loading on those lines. So transmission costs are appropriately included.

As you're looking at the economic dispatch and looking at the effective cost of getting generation or energy from a resource that's across a transmission line and what the cost of that transmission would be -- or that resource would be delivered in that instance. So it's making economic decisions about the use of transmission.

Given that, the flows on transmission are not contractual generally. That's the normal application that, again, based upon how I use the tool, the economic flows are a

result basically of the economic dispatch and the dispatch of those resources and -- so as you're looking at the resources being dispatched and the loads that you're serving, the transmission line flows correspond basically to the energy flows across, you know, those lines based upon economics.

Detailed control of operations: Basically you can -- again, with the inputs and capabilities within the tool, you can specify down to very finite levels of information going in. You can have heat rates changing by hour, for example, based on temperature.

And I believe that's how ML&P is currently looking at some of that data that's going into the model.

Fuel costs can be changing; and you can make those fuel costs changing as frequently as you want to, as well as relative to other costs. And you can also include limits on those fuels to say there's so much -- so much, for example, natural gas available in the region at any point in time and determine the allocation of that fuel.

Again, transmission costs and

limits, all those things can be basically specified down to a very finite level.

You know, the model uses basically vector pointers to say, if this is the fuel I want to use; and this is the price, you point it down to a yearly amount that points to a monthly amount that points to an hourly amount; and you have specified it down to an hourly level.

Spinning and non-spinning reserve requirements are specified in the model. It honors and makes economic decisions about which units and which ones are being held in reserve for spinning and non-spinning operating reserves to assure reliability. And, again, it's an economically determined amount.

You have user control on how the model operates and does that; and basically you can specify it from within a very finite area in terms of how much spinning reserve, for example, is required; or you can look at it from a broader pool perspective or both if you want to.

So it will look at, you know, both of those as being overriding or necessary amounts required for reserve purposes to assure reliability. So, again, a lot of flexibility.

Okay. Basically the AURORA dispatch model provides, you know, that incremental clearing value, if you will, at any point in time. And that information allows you to do a lot of powerful things.

So it not only is a forecasting tool of prices and dispatch, but given that information, you can look at basically the positions that you're -- taken in the market, which includes power cost positions -- could be individual resources; it could be the cost of serving a customer -- and you can look at those particular positions taken in the market; and you can also then exercise the range of potential outcomes.

For example, you know, if tomorrow's weather's going to be plus or minus five degrees and that's going to change my demand, you can basically have those as inputs; and it will give you the range of results. So it's a very powerful use of the tool.

The other extremely powerful use of the tool is long-term planning. Given the value of generation; looking at the dispatch of those units and the value that they're creating; given

the clearing prices, if you will, at any point in time as an economic measure, you can make assessments and determination about the long-term value of those resources. And that includes new resources that you are potentially going to build, as well as existing resources and their retirements.

So it looks at forward-looking costs; it looks at investment costs; it looks at the economic value based upon how those units are being operated based upon the market prices, and then making decisions about which units have future-looking positive value and which ones do not.

So, again, back to, I guess, the application to the Railbelt utilities. Again, my presentation is to say that AURORA is a viable tool and is well suited for the Railbelt power pool.

It -- again, it's a least cost economic dispatch solution; it's very transparent and allows you to, you know, analyze and assure yourself that that, in fact, is the result; decisions are made independent of ownership. And I think -- again, the previous presentation bears

that out.

But to say that there's -- there is no real game play and you can bid resources in the tool if you wanted to say I've got certain control over a certain number of resources and you can do that, but where you can have the model just flat out say that resources are being economically dispatched as if they were independently owned.

So you're looking at kind of a market competitive perspective, if you will, to come up with the overall efficiency.

So it does come down to, you know, how to achieve the least cost solution. Model transparency; and, again, I guess if I was to put one super highlight on where I think the real opportunity in value for AURORA is, is its transparency.

And, again, as Jim pointed out, it's kind of -- going to be available or having the use of this tool allows you to go in and really dig into and evaluate and see kind of the -- all the input/outputs and see what's happening in the tool.

It's not a black box that allows you to really investigate and explore the tool.

Extremely flexible. So as you have daily changes if you said, okay, I all the sudden have a plant that is -- come offline, you can immediately do a new economic dispatch every 15 minutes, if necessary, to look at what is the effective -- based upon the economic conditions, based upon the future forecast of conditions over that finite time period.

So you have a lot of flexibility to set up the model, run it repetitively as you have changes in your system.

And that ends my presentation. And, you know, willing to answer any questions or whatever might be useful.

CHAIRMAN PICKETT: Thank you. Commissioner questions? Commissioner Wilson, do you have any questions? Commissioner McAlpine?

COMMISSIONER McALPINE: Yeah, I -- a couple. First of all, this is, I guess, for either of you; is this already being employed by ML&P?

MR. TRENT: Yes, sir.

COMMISSIONER McALPINE: And to what degree in terms of connectivity with other utilities, what are they required to do?

MR. TRENT: Nothing. They don't have to do anything at all, sir. The entire program will take care of the interconnection agreement. Our plan is to, on a day-ahead basis, advise each of the utilities the proper runtimes for their equipment.

COMMISSIONER McALPINE: And so they're required to, I guess, take it for granted that the information that they're getting from you and vice versa is accurate information?

MR. TRENT: I don't like the term "taking for granted," but --

COMMISSIONER McALPINE: I'm thinking of garbage in, garbage out; but be that as it may.

MR. TRENT: Neither of those terms excite me. We think that the database we're creating is extremely accurate.

We're going to give each of the utilities the information on a day-ahead basis upon which they can decide which of their machines to run and not to run based on the analogues coming from AURORA. Their choice is to do it or not to do it.

During this first year trial period

we will track the savings or lack thereof, depending on their decision process. This is still purely voluntary for the first year.

COMMISSIONER McALPINE: As seen from the prior presentation, that an integral part of the Texas operation was the auditing; and does this allow for or require auditing on the part of the participating utilities?

MR. TRENT: They don't have to do anything, sir. We'll do all of the auditing and paper trail to make sure that they are either saving money by engaging in economic dispatch or not.

And during the course of the year we will also sophisticate ML&P's use of AURORA in its own sense. At the end of this year we'll know whether it's a good tool or not.

COMMISSIONER McALPINE: Okay. No further questions.

CHAIRMAN PICKETT: Commissioner Rokeberg, do you have any questions?

COMMISSIONER ROKEBERG: Yes.

CHAIRMAN PICKETT: Please proceed.

COMMISSIONER ROKEBERG: I am concerned about just understanding this,

particularly regarding the basic assumptions and the rules that -- being utilized now with the program.

It seems to me that given the description of the ERCOT formation and the process by going through the stakeholder rulemaking, they came up with certain assumptions about the protocols to be used within their own dispatching areas and their -- presumably would be the foundation of the assumptions used to create the equations and algorithms for the computer program.

So could Mr. LeVee speak to how the program is functioning here in the Railbelt regarding that and where the rules of the road are being decided?

MR. LeVEE: I may be deferring to Jim on that question. But, again, kind of the fundamental operations of the tool is to look at it from, again, the economic dispatch to put in, you know, any real parameters and constraints that might exist.

So you're trying to, again, engage the model to look at it from an economic dispatch perspective. And if there are parameters and things that are -- again, electrically limitations

and constraints that need to be incorporated in the tool, then they are addressed; otherwise, kind of the economics as far as any contracts or other sort of things that may be somewhat uneconomic considerations.

Again, those can be looked at separately as well. And an analysis can be made as to why those may or may not be economic. But basically it's an economic determination.

COMMISSIONER ROKEBERG: If I could follow up with, Mr. Trent, perhaps; at what stage are we at now in terms of its maceration of use, or using it a -- of the forecast tool, a simulator, or an actual model for operations?

And if you're using it operationally, can you give us an example, perhaps, to better illustrate that?

MR. TRENT: We're using it operationally on a day-to-day basis now, and our use is simply a day-ahead basis where the software program allows us to determine economically which of the machines in our portfolio we run and for how long or not to run on a daily basis. And we're using that --

COMMISSIONER ROKEBERG: That's in

your own generation fleet, or are you reaching out to other utilities now?

MR. TRENT: Currently we're using it for our own generation fleet. But our proposal is to reach out to all the utilities within the Railbelt and provide day-ahead economic decisions on which of their machines in their portfolio are fiscally operational for a particular period of time.

COMMISSIONER ROKEBERG: And would you propose to be using the dispatch of gas, for example, for Bradley Lake power; or -- I mean, that would be worth most presumably if there would be agreement; is that correct?

MR. TRENT: I'm sorry, sir, would you repeat that question?

COMMISSIONER ROKEBERG: Well, how does it apply to Bradley Lake; would that be -- would you be taking over the -- like the dispatch services from Chugach for that particular generator if they opted in for your system?

MR. TRENT: If Chugach were to opt in to the program, we sincerely hope they consider this opportunity. We would provide them with economic information upon which they would

predicate decisions on which machines at SPP to run or not. It'd entirely be their choice.

COMMISSIONER ROKEBERG: And how do you come up with the qualification of the economic -- discrete economic integration period for each generational unit?

MR. TRENT: AURORA will consider all of the running aspects of that machine; whether it be cost of fuel; age of the machine, and heat load efficiency of the machine. All those aspects will be considered in making a simple economic decision which machine is the best to run at any particular time of day and for how long. It's a total objective decision.

COMMISSIONER ROKEBERG: Does it include its financial burden and so forth --

MR. TRENT: Yes, sir.

COMMISSIONER ROKEBERG: -- on a discrete basis? Okay.

MR. TRENT: Every cost aspect of the machine will be considered before a decision is made through AURORA on how to implement that process on a given 24-hour basis. And we're going to follow up on an hour -- hourly basis to make sure that our decision is accurate.

COMMISSIONER ROKEBERG: And you see this as, perhaps an incremental first step or a more simplified way to introduce a -- some type of ISO or USO potentially or in lieu of; or do you have a long-range vision for your plan?

MR. TRENT: Our thought process is simply this: That the Railbelt has been considering a variety of considerations over the years, and none of which have borne fruit in terms of a decision process. As a consequence, the proverbial can has been kicked down the road for decades and decades.

While that's happening, there is an urgency, at least in our mind, to engage in some kind of economic reliability within the Railbelt. We've got five utilities out there that admittedly do things their own way and very intelligent people running their utilities as best as they should.

We think there's an opportunity to unify that opportunity with all of the portfolios out there and produce some kind of economic savings. How much savings? I don't know.

We hope to find in the first year whether we're saving $1 or a million dollars, and

I don't know those numbers yet. The reason for the first year trial is to ferret out those particular answers.

COMMISSIONER ROKEBERG: So what about things such as stranded costs and that, does the program account for that type of --

MR. TRENT: I'm going to turn to the program expert and ask you to answer that question.

MR. LeVEE: Yeah, generally fixed costs and so forth are not a consideration in the economic dispatch function. Again, if those resources are optimized, then they will produce value, if you will, that will help in offsetting the fixed charges. So they may or may not exceed, you know, the -- what the fixed cost recovery, for example, would be of those resources.

So the economic decision function in AURORA is primarily based upon variable cost operation. And as we talked about long term as well, you know, the recovery of the fixed charges for resources and so forth have to be met and satisfied as it looks at long-term operation of resources and which resources get established.

So it is recovering fixed costs

based upon the prices established in the tool based upon market price concepts.

MR. TRENT: One of our thought process is -- Commissioners, is that while we all, as stakeholders, are evaluating the proposals in front of us now and we all are seriously doing that, there is an urgency to engage in some kind of economic savings for the benefit of the ratepayers. We're willing to step up, ML&P, and help do that right now today.

COMMISSIONER ROKEBERG: Additionally, can you -- is it -- is the functionality of the program able to identify constraints in transmission and workarounds; or could you comment on that?

MR. TRENT: The simplest answer is, yes, sir, it can. But I'm going to ask Mr. LeVee to give you a more detailed explanation.

MR. LeVEE: As it's doing its economic dispatch, it's recognizing when those transmission constraints occur. So it actually includes nomogram-type thinking on transmission.

So you can specify, again, with pretty much transmission-type logic how resource constraints are -- when they are met and when

there's no longer transmission capability.

So it's doing economic dispatch and loading those transmission lines basically for each hour of dispatch; and when it reaches periods of time when it's hitting those constraints, then the transmission is fully subscribed.

MR. TRENT: As --

COMMISSIONER ROKEBERG: And, Mr. Trent, could you tell me, would -- it'd be most ideal utilizing this program to have a single dispatcher for the entire Railbelt?

MR. TRENT: During our trial period it would be ML&P being that single dispatcher; but ultimately, yes, sir, you're on the right track. And that might be -- that might be embodied in whatever process we finally select; whether it's an ISO or a TRANSCO or whatever's going to come down the pike.

But while that's happening, while the decision process is en vogue, we need to do something now to produce some kind of savings. We can't wait any longer.

COMMISSIONER ROKEBERG: Thank you, Mr. Chairman. Thank you, Mr. --

CHAIRMAN PICKETT: Commissioner

Patch, do you have any questions?

COMMISSIONER PATCH: No questions. Thank you very much, Mr. Chairman.

CHAIRMAN PICKETT: Just a couple of questions. I think the first one is for Mr. Trent. It sounds like this is just sort of a shakedown trial period to see if the model is applicable and actually -- I mean, we've looked at a lot of modeling results; but they've been hypotheticals --

MR. TRENT: Yeah.

CHAIRMAN PICKETT: -- and we've seen in the sensitivities, depending on the assumptions that you plug into them, how what -- so this would be a real-world sort of test --

MR. TRENT: Your analysis is absolutely correct. We want to know if it's going to work.

CHAIRMAN PICKETT: And based upon your understanding in this trial period and your understanding of the current regulatory environment with statutes and our regulations, are there any specific actions that the RCA would need to take with this?

MR. TRENT: Thank you, Chairman

Pickett, for that question. No, you don't have to do anything. Just enjoy the process.

CHAIRMAN PICKETT: Enjoyment is not a word I have typically associated with the electric industry in the Railbelt, but I'll --

MR. TRENT: Well, we're being innovative here, sir.

CHAIRMAN PICKETT: Okay. And probably, Mr. LeVee, this would be a question for you. When you look at the transmission situation in the Railbelt from the southern part clear up to the northern part and the balkanization of how things are handled and the recent changes over the last couple of years, the model adequately has the capacity to -- you know, obviously Bonneville uses this, they're sort of playing to the FERC jurisdictional game so that they understand how that works.

But in our case with the different transmission tariffs and -- can you address that? Have you done simulations as to how that --

MR. LeVEE: The simple answer is, no, I haven't done the simulations. So I think there's opportunities, so I guess I'll speak to opportunity as opposed to analysis as this point.

I think that with the tool and the capabilities that are in the tool, you know, there's a lot of potential for exploring a lot more information and thought process on the tariffs, the use of the -- that transmission, which becomes part of the economic dispatch question.

So I think, you know, pricing of transmission and capital recovery of investment and all of those things and how that occurs can be looked at pretty -- you know, given those capabilities and abilities to change that data and information in the tool to see how that affects economic dispatch and the resulting flows of revenues basically over those transmission lines.

CHAIRMAN PICKETT: And this final question probably is most applicable to Mr. Trent and piggybacks of a Commission -- Commissioner Rokeberg's question. In terms of the actual dispatching process for this trial period, you know, you're aware MEA has a one year from back in April agreement with Chugach --

MR. TRENT: Yes, sir.

CHAIRMAN PICKETT: -- to provide dispatching services, so presumably with MEA as a

signatory to this agreement --

MR. TRENT: Yes, sir, that's correct.

CHAIRMAN PICKETT: -- do -- that's all --

MR. TRENT: It's considered in --

CHAIRMAN PICKETT: -- been addressed and figured out --

MR. TRENT: -- considered in --

CHAIRMAN PICKETT: -- and Chugach is in the loop and --

MR. TRENT: -- in the process, yes, sir, that's absolutely correct. We don't intend to impinge on that relationship at all, but offer to MEA and Chugach a fiscal opportunity to do better.

CHAIRMAN PICKETT: And they can look at the opportunities and decide to do it or not. And at the end of the one-year period, there's going to be some sort of reporting to say, here are the opportunities we capitalized on and the savings, and these are the opportunities that, perhaps, we could have had but you didn't take; so is that correct?

MR. TRENT: Yes, sir, that's

exactly our plan. We want to know if it's going to work or not. It's time to do something.

Your consultant -- and I agree with a lot of the things that he said -- said this: In essence, we studied this thing to death; let's quit studying it, let's do something.

Years ago when I worked at Northeast Utilities, my staff made a needlepoint of me, which I take great pride in, that showed two vultures sitting on a fence; and the caption was, "Patience, hell, let's kill something." It's time we kill something.

CHAIRMAN PICKETT: I hope you're not looking at behind the dais here. Okay. I think it's been a very interesting -- it's almost like this AURORA is a pre-2001 ERCOT sort of thing that could help, perhaps, move the ball in a direction that can result in something different.

And I hear what you're saying about the timing because even if the Commission, at the end of the day in its determination and recommendation to the Legislature speaks with absolute specific clarity on a specific direction, just the implementation of that -- you're a couple years out --

MR. TRENT: That's right.

CHAIRMAN PICKETT: -- realistically. So, again, thank you very much for being here this morning. And before I close out agenda item number four, I would strongly recommend for anybody online or in the hearing room or interested parties of the utilities, anything you've heard this morning, either from the Chugach presentation or the ML&P presentation that you would like to support, critique, offer additional comments, please get those in to the Commission no later than the 17th of June.

Again, thank you for being here. That will close agenda item number four.

Is there any other business that needs to come before the Commission this morning? I have none. Commissioner Patch or Commissioner Rokeberg, do you have any other business to come before the Commission?

COMMISSIONER PATCH: We do not, no.

CHAIRMAN PICKETT: Seeing none, agenda item number five is closed. Agenda item number six, does the Attorney General have need for an executive session?

MR. GOERING: Yes.

CHAIRMAN PICKETT: Please state the nature of the need.

MR. GOERING: The Commission is currently involved with three appellant litigation matters; they are 3AN-14-08890 Civil, which is the appeal of U-13-203, 204, Order 10; 3AN-15-05678 Civil, which is the appeal of the final order in U-14-001; and S-15696, which is the Supreme Court appeal of Docket U-12-004.

And I would like to brief the Commissioners on the status of each of those matters and seek the Commission's guidance on litigation strategy.

CHAIRMAN PICKETT: Is there a motion to go into executive session to address the matters identified by the Attorney General?

COMMISSIONER McALPINE: So moved.

CHAIRMAN PICKETT: Second?

COMMISSIONER WILSON: Second.

CHAIRMAN PICKETT: All those in favor say aye.

COMMISSIONERS: Aye.

CHAIRMAN PICKETT: We'll take --

COMMISSIONER WILSON: Roll call.

CHAIRMAN PICKETT: Okay. I'll take

a poll for those -- Commissioner Rokeberg, do you favor going into executive session?

COMMISSIONER ROKEBERG: Yes.

CHAIRMAN PICKETT: Commissioner Patch?

COMMISSIONER PATCH: I vote aye. I do believe an executive session is called for.

CHAIRMAN PICKETT: All of the Commissioners, a unanimous vote have voted to go into executive session. I would ask everybody to clear the hearing room; and for all of you online, with the exception of Commissioner Patch and Rokeberg, please disconnect.

(Off record.)

(Executive session.)

(Commissioners Patch and Rokeberg no longer online.)

CHAIRMAN PICKETT: We are back on the record; it is approximately 11:59 p.m. We have just concluded executive session. Did the Attorney General get the direction requested in executive session?

MR. GOERING: Yes. Thank you, Chairman Pickett.

CHAIRMAN PICKETT: Is there a

motion to adjourn at approximately 12:00 noon?

COMMISSIONER WILSON: I move that we adjourn.

COMMISSIONER McALPINE: Second.

CHAIRMAN PICKETT: All those in favor say aye.

COMMISSIONERS: Aye.

(Off record.)

TRANSCRIBER'S CERTIFICATE

I, Brooklende D. Leavitt, hereby certify that the foregoing pages numbered 3 through 88 are a true, accurate, and complete transcript of the Public Meeting of the Regulatory Commission of Alaska, held on June 3, 2015, transcribed by me from a copy of the electronic sound recording to the best of my knowledge and ability.

_____ _____

Date Brooklende D. Leavitt, Transcriber

Developing an Equitable and Economic Cost/Benefit Allocation Structure for an Alaska Railbelt Unified System Operator

PRESENTED TO THE RCA JUNE 3RD, 2015

Agenda

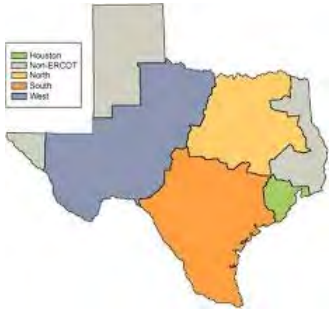
- Introduction and Background
- The Independent System Operator Concept and Practice
- ISO Responsibilities on Economic Cost/Benefit Allocation
- Economic Cost/Benefit Allocation Straw-man for Alaska Railbelt
  - The Process
  - Economic Cost/Benefit Allocation Categories
  - Example

Introduction and Background

- Teneo Consulting Experience- North America
  - Seven years employed at two ISOs (CAISO and ERCOT)
  - Nine years with two member companies representing diverse generation fleet, renewable energy, demand response, power marketing and retail services
  - Operations and Financial experience in 7 North American ISOs (CAISO, ERCOT, SPP, MISO, NYISO, PJM, OIESO)
  - Market Design and Testing for ERCOT and SPP
  - Stakeholder Chair for 4 Sub-committees in ERCOT
  - Testimony before the Public Utility Commission of Texas
- Europe
  - Operational and commercial systems analysis and RFP development for EirGrid in Ireland, ISO equivalent for the Single Electric Market and their redesign effort into Pan European Integrated Single Electric Market
  - Much smaller market (approx. 6K MW) than the North American ISOs and a less complex market structure

Independent System Operator

ISO Evolution- ERCOT Case Study



2001

2015

- Regional Pricing- 4-zones
- Balance Responsible
- Merit Order Dispatch- Economic
- Out of Merit Dispatch- Congestion and Must Run
- Reserves
- General Market Mitigation, Monitoring

2001 Model most likely applicable for the Railbelt USO structure

- Nodal Pricing- Generators, Load Zones and Trading Hubs
- Day Ahead Market
- Financial Transmission Rights- Options and Obligations
- Security Constrained Economic Dispatch
- Reserves Co-optimized (ORDC)
- Ex-ante Market Mitigation
- Independent Market Monitoring

ERCOT Evolution Summary

- ERCOT like other ISOs evolved from loosely coordinated to more unified operations
- Operational efficiency transitioning from 10 separate control areas to a single control area
- Improved access and options for existing utilities and IPPs
- Bilateral and self-supply services made up 95% of energy transactions subjecting a very small portion to Energy Balancing services
- Evolution was stakeholder driven with Regulatory input and oversight, with ISO input on reliability

Real Time Dispatch vs Settlement

- Separation of real-time economic dispatch from financial obligations
- In real-time the system is dispatched securely and economically (SCED) as a single system
- Next day settlement settles actual real-time results with pre-existing schedules, bilateral contracts and other obligations
- Settlement uses predefined stakeholder developed protocol equations to settle
- ***Due to the lack of a competitive market in the Railbelt, the term "offer" is defined as an auditable cost based price curve for each generating unit***
- Real time dispatch results in a System Marginal Price which represents the last generator dispatched in merit order to meet the last increment of load
  - Merit Order represents a offer stack by generator for available MW at their cost starting with the lowest cost unit to the highest cost unit
- Utilities can protect themselves financially from potential high System Marginal Prices by scheduling self-supply or purchase energy from other parties

Example 1 Assumptions

- Offer information represents unit actual cost
- Three Utility Example under the following scenarios
  - Utility A Self Supplying and Purchasing Energy to meet their load forecast
  - Utility B Self Supplies its load forecast
  - Utility C Self Supplies its load forecast
  - Utilities A and B offer to supply additional capacity to the USO
- Energy Balancing Resource – metered generation provided over/under self supply
- Energy Balancing Demand – metered load over/under forecast
- Demand Obligation represents the sum of self supply and purchased energy to meet load forecast
- Supply Obligation represents the sum of self supply and sold energy from each generator

Cost/Benefit Allocation Example 1

Utility A			
	Supply	Obligation	Party
Self Supply (SS)	50		A
Demand Schedule (DS)		50	A
Demand Purchase (DP)		25	A
Demand Trade (DT)	25		C
Balanced Schedule	75	75	
Supply Obligation (SO)	50		
Demand Obligation (DO)		75	
Metered Gen (MG)			
Metered Load (ML)			
	Schedule	Bid MW	Bid $
GEN1	25	25	$100
GEN2	25	15	$120

Utility B			
	Supply	Obligation	Party
Self Supply (SS)	100		B
Demand Schedule (DS)		100	B
	100	100	
	100		
		100	
Metered Gen (MG)			
Metered Load (ML)			
	Schedule	Bid MW	Bid $
GEN3	50	150	$80
GEN4	50	25	$70

Utility C			
	Supply	Obligation	Party
Trade Sale (TS)	25		C
Supply Trade (ST)		25	A
Self Supply (SS)	200		C
Demand Schedule (DS)		200	C
	225	225	
	225		
		200	
Metered Gen (MG)			
Metered Load (ML)			
	Schedule	Bid MW	Bid $
GEN5	25	25	$40
GEN6	200	0	$30

Merit Order Bid Stack- All Gen Bid to USO		
Unit	Bid MW	Bid $
GEN6	0	$30
GEN5	25	$40
GEN4	75	$70
GEN3	150	$80
GEN1	25	$100
GEN1	15	$120

1. Utility A Purchases 25 MW from Utility C for $40 /MW and Self Supplies remaining Demand Obligation from GEN1 and GEN2, bids in additional capacity at each unit
2. Utility B Self Supplies its Demand Obligation from GEN3 and GEN4 and bids additional capacity at both resources
3. Utility C Self Supplies its Demand Obligation and sells 25 MW to Utility A at $40

Cost/Benefit Allocation Example 1

Utility A			
	Supply	Obligation	Party
Self Supply (SS)	50		A
Demand Schedule (DS)		50	A
Demand Purchase (DP)		25	A
Demand Trade (DT)	25		C
Balanced Schedule	75	75	
Supply Obligation (SO)	50		
Demand Obligation (DO)		75	
Metered Gen (MG)	50		
Metered Load (ML)		75	
	Schedule	Bid MW	Bid $
GEN1	25	25	$100
GEN2	25	15	$120

Utility B			
	Supply	Obligation	Party
Self Supply (SS)	100		B
Demand Schedule (DS)		100	B
	100	100	
	100		
		100	
Metered Gen (MG)	135		
Metered Load (ML)		100	
	Schedule	Bid MW	Bid $
GEN3	50	150	$80
GEN4	50	25	$70

Utility C			
	Supply	Obligation	Party
Trade Sale (TS)	25		C
Supply Trade (ST)		25	A
Self Supply (SS)	200		C
Demand Schedule (DS)		200	C
	225	225	
	225		
		200	
Metered Gen (MG)	200		
Metered Load (ML)		210	
	Schedule	Bid MW	Bid $
GEN5	0	25	$40
GEN6	200	0	$30

Merit Order Bid Stack- All Gen Bid to USO		
Unit	Bid MW	Bid $
GEN6	0	$30
GEN5	0	$40
GEN4	75	$70
GEN3	150	$80
GEN1	25	$100
GEN1	15	$120

1. Utility C GEN5 Unit trips
2. Utility C Actual Demand is 10 MW higher than forecasted
3. USO dispatches additional capacity from GEN4- 25 MW and GEN3 at 10 MW to balance the system setting the System Marginal Price (SMP) for Energy Balancing at $80

Cost/Benefit Allocation Example 1

Cost/Benefit Allocation				
Utility A	MW	Price	Allocation	Description
Purchase from U-C	25	40	($1,000.00)	Purchase from Utility C at Trade Price
Energy Balancing Resource	0	80	$0.00	Supply Obligation of 50, Metered Gen 50 No Balancing Allocation
Energy Balancing Demand	0	80	$0.00	Demand Obligation 75, Metered Load 75, No Balancing Allocation
Total U-A			***($1,000.00)***	
Utility B	MW	Price	Allocation	
Energy Balancing Resource	35	80	$2,800.00	35 MW provided by USO dispatch
Energy Balancing Demand	0	80	$0.00	Demand Obligation 100, Metered Load 100, No Balancing Allocation
Total U-B			***$2,800.00***	
Utility C	MW	Price	Allocation	
Sale to U-A	25	40	$1,000.00	Sale to Utility A at Trade Price
Energy Balancing Resource	-25	80	($2,000.00)	Supply Obligation 225, Metered Gen 200, Balancing Allocation at SMP
Energy Balancing Demand	-10	80	($800.00)	Demand Obligation 200, Metered Load 210, Balancing Allocation at SMP
Total U-C			***($1,800.00)***	

Example 2 Assumption

- 100 % generation from A, B, C is offered at cost
- No purchase or sale transactions between utilities
- System load remains at 385 MW
- USO will dispatch at generation offers to meet the demand

Cost/Benefit Allocation Example 2

Utility A			
	Supply	Obligation	Party
Self Supply (SS)	0		A
Demand Schedule (DS)		0	A
Demand Purchase (DP)		0	A
Demand Trade (DT)	0		C
Balanced Schedule	0	0	
Supply Obligation (SO)	0		
Demand Obligation (DO)		0	
Metered Gen (MG)	0		
Metered Load (ML)		75	
	Schedule	Bid MW	Bid $
GEN1	0	50	$100
GEN2	0	40	$120

Utility B			
	Supply	Obligation	Party
Self Supply (SS)	0		B
Demand Schedule (DS)		0	B
	0	0	
	0		
		0	
Metered Gen (MG)	185		
Metered Load (ML)		100	
	Schedule	Bid MW	Bid $
GEN3	0	200	$80
GEN4	0	75	$70

Utility C			
	Supply	Obligation	Party
Trade Sale (TS)	0		C
Supply Trade (ST)		0	A
Self Supply (SS)	0		C
Demand Schedule (DS)		0	C
	0	0	
	0		
		0	
Metered Gen (MG)	200		
Metered Load (ML)		210	
	Schedule	Bid MW	Bid $
GEN5	0	25	$40
GEN6	0	200	$30

1. 100% Generation bid into the USO, Demand at 385 MW
2. USO dispatches in Merit Order GEN6- 200 MW, GEN4- 75 MW, GEN3- 110 MW
3. GEN3 sets the System Marginal Price at $80

Merit Order Bid Stack- All Gen Bid to USO		
Unit	Bid MW	Bid $
GEN6	200	$30
GEN5	0	$40
GEN4	75	$70
GEN3	200	$80
GEN2	40	$90
GEN1	50	$100

Cost/Benefit Allocation Example 2

Cost/Benefit Allocation				
Utility A	MW	Price	Allocation	Description
Purchase from U-C	0	$0	$0.00	
Energy Balancing Resource	0	$80	$0.00	No energy provided, load served at lower cost
Energy Balancing Demand	-75	$80	($6,000.00)	Metered Demand at SMP, load served at lower cost
Total U-A			***($6,000.00)***	
Utility B	MW	Price	Allocation	
Energy Balancing Resource	185	$80	$14,800.00	185 MW provided to USO at SMP
Energy Balancing Demand	-100	$80	($8,000.00)	Metered Demand at SMP
Total U-B			***$6,800.00***	
Utility C	MW	Price	Allocation	
Sale to U-A	0	$0	$0.00	
Energy Balancing Resource	200	$80	$16,000.00	Metered Gen 200 MW at SMP, revenue over Unit Cost
Energy Balancing Demand	-210	$80	($16,800.00)	Metered Demand and Forecast Error at SMP
Total U-C			***($800.00)***	

Operating Cost Summary

Example 1 Cost Summary				Example 2 Cost Summary			
Unit	MW	Price	Cost	Unit	MW	Price	Cost
GEN1	25	$100	$2,500	GEN1			$0
GEN2	25	$120	$3,000	GEN2			$0
GEN3	75	$70	$5,250	GEN3	110	$80	$8,800
GEN4	60	$80	$4,800	GEN4	75	$70	$5,250
GEN5	0	$40	$0	GEN5			$0
GEN6	200	$30	$6,000	GEN6	200	$30	$6,000
	385		$21,550		385		$20,050

System benefits from economic dispatch in example 2 by $1,500 due to load being met by most efficient generation dispatched

Utility A Analysis

Utility A Example 1			
Category	MW	$	Cost
Operating Cost			
GEN1	25	$100	($2,500)
GEN2	25	$120	($3,000)
Trade Revenue/Cost			
U-C Purchase	25	$40	($1,000)
Energy Balancing			
Resource	0	$80	$0
Demand	0	$80	$0
Total			($6,500)

Utility A Example 2			
Category	MW	$	Cost
Operating Cost			
GEN1	0	$100	$0
GEN2	0	$120	$0
Trade Revenue/Cost			
U-C Purchase	0	$40	$0
Energy Balancing			
Resource	0	$80	$0
Demand	-75	$80	($6,000)
Total			($6,000)

Utility A benefits by serving their load with more efficient generation

Utility B Analysis

Utility B Example 1			
Category	MW	$	Cost
Operating Cost			
GEN3	60	$80	($4,800)
GEN4	75	$70	($5,250)
Trade Revenue/Cost			
	0	$0	$0
Energy Balancing			
Resource	35	$80	$2,800
Demand	0	$80	$0
Total			($7,250)

Utility B Example 2			
Category	MW	$	Cost
Operating Cost			
GEN3	110	$80	($8,800)
GEN4	75	$70	($5,250)
Trade Revenue/Cost			
	0	$0	$0
Energy Balancing			
Resource	185	$80	$14,800
Demand	-100	$80	($8,000)
Total			($7,250)

Utility B self supplies their own demand and remains neutral while providing additional cost efficient generation to the Railbelt

Utility C Analysis

Utility C Example 1			
Category	MW	$	Cost
Operating Cost			
GEN5	0	$40	$0
GEN6	200	$30	($6,000)
Trade Revenue/Cost			
U-A Sale	-25	$40	$1,000
Energy Balancing			
Resource	-25	$80	($2,000)
Demand	-10	$80	($800)
Total			($7,800)

Utility CB Example 2			
Category	MW	$	Cost
Operating Cost			
GEN5	0	$80	$0
GEN6	200	$30	($6,000)
Trade Revenue/Cost			
	0	$0	$0
Energy Balancing			
Resource	200	$80	$16,000
Demand	-210	$80	($16,800)
Total			($6,800)

Utility C benefits by the net the revenue at GEN6 and its cost to serve load at the System Marginal Price

Appendix- Energy Balancing Algebra

- ISO Principles
- Economic Dispatch and Self Schedule/Bilateral Opportunities
- Proposed Straw-man Document Creation Process
- Sample Algebraic Equations used in the examples

ISO Principles

- Reliability and interconnection standards
- Short-term operational reliability
- Open and Non-discriminatory Transmission Access
- Subject to Regulatory Oversight and Jurisdiction
- Applies Standards and Tariffs
- Short Term and Long Term Planning
- Accurate Accounting of Transactions
- Stakeholder Governance
- Provides input but does not make Policy decisions

Economic Dispatch and Self Schedule/ Bilateral Opportunities

- A utility that self-schedules its own generation to meet its native load requirements for energy capacity and ancillary services in the Daily Operating Plan is essentially insuring its cost of power and ancillary services for the next day .
  - That is to say it is guaranteeing that regardless of the real-time cost of energy and ancillary services it will pay *no more or less* that the cost of running its own generation.
  - Currently, the Daily Operating Plan is complete the evening before the Real-time dispatch begins ostensibly between 3:00 and 7:00 pm
- A utility could self schedule, bilaterally contract or a combination of both for all or part of its native load or buy from the USO at System Marginal Price
  - Depending on economic merit, the self scheduling utility's generators may or may not actually run in the real-time Economic Dispatch
  - If its generation runs it pays its own costs, if it does not run It saves its operating costs and serves its load by more efficient generation at a System Marginal Price

Railbelt Straw-man Process

- Utilizing a simple Unified System Operator concept similar to ERCOT's 2001 ISO model, we will develop a straw-man document for sample Economic Cost/Benefit Allocation rules with sample algebraic equations
- We propose to include initial consultations and Q&A with the Railbelt Utilities
- The straw-man will include but not necessarily be limited to the following categories for Cost/Benefit Allocation Rules:
  - Reserves
  - Energy Balancing
  - Unit Commitment and Operational Security Services
  - Must Run
- The straw-man document could provide Railbelt Stakeholders with an initial starting point for a stakeholder agreed settlement procedure

Railbelt Straw-man Process

- The following categories contain assumptions and topics for consideration, subject to change based on initial discussion with Railbelt Utilities and with the RCA
- Additional details brought up for consideration in each category will be included in the straw-man document but will require further detail and stakeholder vetting
- Details around the frequency of Cost/Benefit Allocation calculations, the granularity for an allocation settlement period (hourly, half-hourly, 15-min etc.) will be considered but not specified or suggested
- A System Marginal Price concept will be utilized for discussion around Energy Balancing Cost/Benefit Allocation, while details on how that price is established should be further vetted
- Socialized costs for services are assumed to be based on demand, but not limited to specifics (e.g. could be period demand or peak demand or some combination of energy and demand)

Straw-man Categories- Reserves

- Consideration for Reserves to include:
  - Regulation, Spinning and Non-spinning services
  - Payment for services can include contracted services and/or competitively bid services
  - Competitively bid services generally settled under a cleared merit order bid stack
  - Payments for Reserves generally paid by demand obligation (e.g. load ratio share or peak demand)
  - Obligation can be met through self providing from internal resources capable of providing reserves
  - Obligation can be met through self arrangement through trades to entities with reserve resources
- Additional details for consideration
  - Determination of the amount of reserves required
  - Consideration for non-performance

Straw-man Categories- Energy Balancing

- Considerations for Energy Balancing:
  - Should entities be Balance Responsible (submitting a balanced schedule for supply and demand obligations)
  - Considerations for self scheduling resources for demand obligations
  - Considerations for trades between parties for supply and demand obligations
  - Load following capabilities
  - Providing Incremental and Decremental bids for available capacity
- Additional details for consideration:
  - Uninstructed deviations
  - Marginal System Price creation
  - Fuel Transfer Costs

Straw-man Categories- UC and OSS

- Considerations for Unit Commitment and Operational Security Services
  - Contracted services can be considered
  - Out of merit dispatches that may require compensation to bid or make-whole allocation
  - Forward commitment for resources to be online and capable of being made whole to start-up, no load and minimum energy costs for the duration of the commitment
  - Cost allocation- are UC costs allocated on a socialized basis by demand or assigned to entities who are “short” to the grid
- Additional details for consideration:
  - Excluding these resources from determining the Marginal Balancing Price
  - Claw-back methodology for "out of merit” Unit Commitment profits (optional)

Straw-man Categories- Must Run

- Considerations for Reliability Must Run:
  - Contract based service based on cost
  - Stand by payment- O&M Based
  - Energy Payment- Fuel Based
  - Make-whole- Must Run unit providing energy when Marginal Price is less than cost
  - Incremental Cost allocation for Must Run (demand based socialized cost)
- Additional details for consideration:
  - Non-performance charges
  - Claw-back of profits

Algebra: Energy Balancing Demand

$$\mathbf{EBD_{UI} = -1 * SUM_{ui}\,(DP * CP)_t + ((DO_{ui} - ML_{ui}) * SMP_i)}$$

Where,

$$DO = DS_{ui} + SUM_{ui}\,(DP)_t$$

Variables:

EBD- Energy Balancing Demand

DP- Demand Purchase (MWh)

CP- Contract Price ($/MWh)

ML- Metered Load (MWh)

DO- Demand Obligation (MWh)

SMP- System Marginal Price ($/MWh)

DS- Demand Schedule(MWh)

u- Utility

i- Allocation Interval

t- Unique Trade

Algebra: Energy Balancing Resource

$EBR_{UI} = SUM_{ui} (TS * CP)_t + ((MG_{ui} - SO_{ui}) * SMP_i)$

Where,

$SO = SS_{ui} + SUM_{ui} (TS)_t$, and $MG_{ui} = SUM_{ui} (RG)_{ru}$

Variables:

EBR- Energy Balancing Resource

TS- Trade Sales (MWh)

CP- Contract Price ($/MWh)

MG- Metered Generation (MWh)

SO- Supply Obligation (MWh)

SMP- System Marginal Price ($/MWh)

SS- Self Supply (MWh)

RG- Resource Generation (MWh)

u- Utility

i- Allocation Interval

t- Unique Trade

r- Unique Resource

In The Beginning there was…

PUFFIN

Presented By: James Trent
ML&P; GM & COO

Centralized Power Pool & Economic Dispatch

ML&P has been using “Puffin” software for the last several years to employ economic dispatch to its generation portfolio.

“Day-Ahead” economic-dispatch strategy reduces generation operating costs.

Puffin's Limitation & Restrictions

ML&P searched nationally and globally for a "state-of-the-art" Economic-Dispatch-Power-Pool software program.

ML&P Introduces "AURORA"

Question:#1

Is Aurora capable of successfully managing Economic-Dispatch-Power-Pool strategies' across the entire Railbelt?

ML&P Introduces "AURORA"

- Aurora software is currently being used extensively both nationally and globally for wide-ranging "day-ahead" economic solutions to mission-critical scheduling problems with complex constraints and resource requirements, quickly and easily.
- Organizations such as NASA , the Boeing Company as well as national and global utilities rely on Aurora to manage "day-ahead" operations more efficiently than is possible using less powerful scheduling systems. In a study conducted by the Boeing company, Aurora economically managed resources more efficiently than software used by Boeing for almost two decades.

AURORA

ML&P Supports "AURORA"

ML&P proposes to sponsor Economic-Dispatch-Power-Pool trial for the entire Railbelt

HEA
ML&P
AURORA
"CPPED"
GVEA
MEA
CEA
SELP

Questions? More Information?

AURORA^{xmp}
Forecasting and Economic Dispatch Model

Presentation to the
Regulatory Commission of Alaska
June 3, 2015

AURORA^{XMP} strengths

- AURORA^{XMP} is user-friendly
  - Built on an XML framework providing easy access to modeling detail and information.
  - Built into AURORA^{XMP} is the ability to generate reports, graphs, charts, etc. useful in the analysis and communication of results
  - Transparency allows for quick and comprehensive analysis of results into nearly any form as specified by the user.
  - Multiple tools allowing for the production of routinely frequented inputs and outputs
- AURORA^{XMP} has a proven record - used extensively in both the US, Canada and abroad
- Unparalleled support from EPIS

Conceptual Overview

- Model simulation of system operation of interconnected loads and resources to achieve *economic optimization*
  - Performs economic dispatch of resources
    - Dispatches lowest to highest incremental cost to fulfill hourly demands
    - Inclusive of transmission paths, costs and constraints. Economic solution is inclusive of the cost and location of resources dispatched.
  - Input detail and model logic provides an accurate simulation of resources having complex operations.
    - Detailed costs and resource operating parameters specified in inputs.
    - Complex algorithms optimize operations given operational constraints.

Topography – System Interconnection

- Construct of system topography is established by ***data input*** and controlled mapping of the data.
  - Regions are identified including loads and/or resources having little transmission cost or constraint.
  - Regions are interconnected to other regions via transmission links with associated costs and limits.

- The resulting topography provides a representation of the electrical connection, allowing for the simulation of the economic dispatch of resources to interconnected loads.

Resource Operating Constraints

- Operating constraints include:
  - Minimum operation periods- includes both minimum "up" and "down" periods
  - Startup costs – fuel and other costs incidental to startup
  - Ramp rates – periods before full resource output is acheived
- Resource dispatch assures "value" over period of operation.
  - Model uses "commitment" logic for resources with run time operating constraints
  - Value must be in excess of *incremental costs* incurred plus any assigned premium prior to commitment for operation
  - Once committed, model makes forward looking decisions about continued operations

Transmission

- Electrical transmission costs and constraints are inherent in costs when energy is transferred between regions.
  - Costs include wheeling costs and losses
    - Wheeling charges based upon revenues to recover investment costs
    - Losses result in additional energy required above demand
  - Detailed inputs specified to reflect costs relative to transmission loading

- Transmission costs appropriately included to assure the economic dispatch of the entire interconnected system.
  - Resource operations consideration of serving loads within the region or transporting energy based upon economic efficiency.
  - Transmission utilization based upon "economic flows", consistent with loads and resource operations.

Detailed Control of Operations

- Down to hourly detail of nearly “all “ inputs including:
  - Heat rates, fuel costs, fuel limits, transmission costs and limits, hydro operations, wind generation … *basically unlimited*.
- Operating (spinning and non-spinning requirements are specified.
  - Operational reserves include both spinning and non-spinning reserves to assure system operations and stability.
  - Flexibility and optimization are incorporated into resource reserve considerations
  - May be specified within a regions or to a broader pool.

AURORA^{XMP} also provides

- Analysis of positions (power cost) and risk analysis
  - Total power cost to service customers
  - Value of all resource operations
  - Potential range of outcomes (risk) under varying conditions
- Long-term Resource Planning
  - Model determines resource options having greatest achieved value inclusive of the forecast of market energy prices and anticipated operation under conditions of economic dispatch.
  - Planning reserve requirements achieved as part of resource valuation.

Application for Railbelt Utilities

- **AURORA^{xmp}** is well suited for the Railbelt Power Pool
  - Economic dispatch provides the **least cost, most efficient solution** to serve customers.
  - Economic dispatch **decisions are made independent of ownership**, solution identifies true operating constraints including fuel supply limitations to achieve optimal marginal cost benefits.
  - **Model transparency** is a strong and essential attribute of AURORA^{XMP} (not a black box model), key to economically dispatch the Railbelt's resources.
  - **Input flexibility** allowing for updated information to include plant operations, fuel prices or any other conditions allowing for incorporating real time conditions.

Thank you for allowing me time for this presentation today!

Dave LeVee
Principal – PwrCast Inc.

STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners: Robert Pickett, Chairman
Stephen McAlpine
T.W. Patch
Norman Rokeberg
Janis W. Wilson

REGULATORY COMMISSION OF ALASKA
701 West Eighth Avenue, Suite 300
Anchorage, Alaska

PUBLIC MEETING

June 17, 2015
9:00 o'clock a.m.

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P R O C E E D I N G S

(On record - 9:00 a.m.)

CHAIRMAN PICKETT: This is a public meeting of the Regulatory Commission of Alaska. It's Wednesday, June 17th, 2015. It's 9 o'clock a.m. With me on the dais are Commissioners Norman Rokeberg, Commissioner T.W. Patch, Commissioner Stephen McAlpine, and Commissioner Janis Wilson, and I'm Bob Pickett, Chairman of the Commission.

Agenda item No. 1 is public participation. For anyone who would care to address the Commission, please keep your comments to less than five minutes. Is there anyone in the Anchorage hearing room who would care to address the Commission this morning?

If so -- we'll let the gentleman -- please make sure your mike is on, identify yourself, and proceed.

MR. McKEE: Yes. My name's Charles McKee. I spoke here before on this very subject of the evaluation of the Alaska Railbelt electric transmission system.

And I have here three letters, different -- first, Citizens and Advisory

Anchorage audience who would care to address? Please come up to a microphone, make sure it's on, and identify yourself for the record.

MR. JOHNSON: Good morning. Doug Johnson, Ocean Renewable Power Company. I'm currently the business -- director of business development for Ocean Renewable Power in Alaska, and the first Alaskan investor in Ocean Renewable Power Company.

We make energy for moving water without damming or impounding water. I'm here today to speak on behalf of the independent system operator concept that's being considered here in the State. It's really important for this to move forward for a couple of reasons. Mainly, we need equal access to the market.

As an independent power producer, Ocean Renewable Power Company has been successful. We're the first American company to actually make energy from the tide and deliver that energy to a utility. We actually are only able to do that in Maine, because we were able to work through an ISO, and that facilitated the process. It worked well and allowed us to get our power to market.

We see the same challenge here in Alaska. You know, if we want to come to market with our electricity, right now we're dealing with six different utilities here in the Railbelt. So this would be extremely efficient and effective to have an independent system operator working -- oversight for our power grid here in Alaska that's presently in the Railbelt and as we expand that potentially.

The other thing that's really important for us is, as we look at this and as an independent power producer and a member of the Alaska Independent Power Producers Association, we see this as a real opportunity to create a real fair playing field for the market, so that all power producers have equal opportunity to get their power to market. This is particularly important for new and emerging technologies where there are some startup industries and startup capacity.

So the way that we see this playing out is having an independent system operator really allows for a much more efficient and effective system and a much more fair environment to operate in.

That's really my remarks today.

CHAIRMAN PICKETT: Okay. Thank you very much. We'll now go on --

Oh, excuse me. Commissioner Rokeberg, did you have a question?

COMMISSIONER ROKEBERG: I do.

CHAIRMAN PICKETT: If you wouldn't mind coming back up.

MR. JOHNSON: Sure. Good morning, Commissioner.

COMMISSIONER ROKEBERG: Good morning. Thank you.

My curiosity has gotten the best of me. Could you in a nutshell describe the nature of your company and what technology you're using?

MR. JOHNSON: You bet. Our company, Ocean Renewable Power Company, works in hydrokinetics; so what we basically have developed is a turbine that operates in the current. As the current flows to the turbine, the turbine spins, and it produces electricity.

So that was -- the very first turbine that we operated in Maine there in the Bay of Fundy was about a 125-kilowatt system,

and we're currently testing a 25-kilowatt system in the Village of Igiugig on the Kvichak River. We had that system operating last summer, and we'll be there again this summer. We're very excited about this particular technology, because it has the ability to operate in the riverine environment as well as the tidal environment. So we've basically scaled the tidal system down to operate in the rivers.

We'd love to continue the development of the technology and work to actually have this operate ultimately some day in Cook Inlet, which is a truly world-class tidal energy resource.

COMMISSIONER ROKEBERG: Would the nature of the water quality and the glacial silt in the Cook Inlet area have any impacts on turbine operations and the ability to operate?

MR. JOHNSON: Great question. We've been working through those issues as we've tested. We've actually run our turbine bearings and seals in a flume at the university for testing how the abrasion of that sedimentally laden water works on the bearings

and seals and have come up with some really unique solutions to that. So we're confident that we can operate in the Cook Inlet environment as well as rivers that have high suspended sediment loads.

One of the bigger challenges beside that in the rivers is debris. We're currently addressing the debris. We're working with the University of Alaska with a debris-diversion device that's being developed. It's actually working quite well.

COMMISSIONER ROKEBERG: I'll wrap it up and invite you to return to a public meeting with a more extensive presentation. I'd be very interested.

Could you tell me how scalable your technology is at this juncture?

MR. JOHNSON: Very scalable. We start with a small, modular device we call our turbine generating unit. Again, in the tidal environment we're looking at those being about a 125-kilowatt unit scaled up to a quarter megawatt or 250-kilowatt units. We can put four of those together in a modular system we call the ocean current generating module, which

was a megawatt module. Those are the systems that we'd be deploying in Cook Inlet ultimately.

COMMISSIONER ROKEBERG: Thank you. Please give me a call, or the Chairman, and we'll invite you back.

MR. JOHNSON: You bet. We'd be happy to do it after this summer's success in the field. Thanks.

CHAIRMAN PICKETT: Thank you.

I will now turn to anyone online who would care to address the Commission. Is there anyone?

Peter, could I get back to you? I'd like to give the folks online a shot, then we'll bring you up.

Is there anyone online who would care to address the Commission at this time?

Hearing none, Peter, you can come up to the table now and identify yourself for the record.

MR. CRIMP: I'm Peter Crimp of Anchorage representing myself.

As a long-term -- long-time Railbelt ratepayer and resident, I support the

establishment of a not-for-profit, nonasset-owning private corporation overseen by the RCA with the authority to ensure fair and open access to the Railbelt transmission system, consistent with the principles laid out by the Renewable Energy Alaska Project's 4/1 submittal.

I won't attempt to rehash the substantial benefits of an ISO-like entity that have already been stated clearly by others, but I'll simply note that the Chugach Electric Association's recently released study, May 28, estimates $581 million in net savings from the establishment of such an entity. That's without transmission improvements -- or that would follow from -- after the establishment of an ISO.

So an independent, professional, stakeholder accountable ISO would develop standards and protocols to facilitate transmission system improvements. They're likely to reduce costs further and improve reliability, resilience, and prospects for renewable energy.

Many Railbelt ratepayers like me

have been dismayed by the increasing signs of problems in our power system: Litigation, rate increases due to redundant generation, barriers to renewable energy projects. The fact that these problems are happening despite our utilities' high level of commitment and good intentions, I would say, indicates that we face systemic problems, and such systemic problems call for systemic solutions.

So, in conclusion, I just urge the Commission to take immediate action to facilitate establishment of an ISO-like entity.

Thank you.

CHAIRMAN PICKETT: Thank you, Peter.

Is there anyone else in the Anchorage -- please come forward to the microphone and identify yourself.

MR. ROSE: Thank you. My name is Chris Rose. I'm the Executive Director of Renewable Energy Alaska Project, or REAP, and I am here to testify in support of an independent system operator.

We're a coalition of over 80 organization, including some of the Railbelt

utilities, independent power producers, Native corporations, and other NGOs.

Since 2004 we've been advocating for renewable energy both with the public and with policymakers. We believe renewable energy is important because it's local; it's clean; and it's inexhaustible; but most importantly, we believe it's important because it's stably priced. There is no fuel cost associated with renewable energy. The power purchase agreements for both Bradley Lake and Fire Island are great examples of long-term contracts that have locked in benefits and predictability for both consumers here in the State and also for anybody who would like to invest in the State, because energy is always one of the biggest costs of doing business.

In an increasingly uncertain world we believe that the value of predictably priced energy for an entire region has a lot of value. We may not be able to put the exact value on it, but it's a big value, I would argue. However, today the Railbelt is still more than 90 percent fired by natural gas, and there is an uncertainty over the price of

future gas. We don't know how long the term of the contract's going to be. They're becoming much shorter. Also, because we now have assets that are expected to run for 25 years, brand-new natural gas assets that have been constructed, I would argue that there's very little predictability over what the price of gas for those assets is going to be in year 5 or 10 or 15 or 20, let alone 25.

So as we move -- as Alaska moves toward our goal of shipping gas off a natural gas pipeline, I think we have to remember that the export price for that gas is going to drive the local domestic price. Our market is just far too small to be driving that price. In fact, we've been producing oil here for almost 50 years, and we've never impacted the world price of oil, and we've never gotten a hometown discount for oil. So we cannot expect to get that hometown discount for natural gas. That's why renewable energy and predictably priced energy is really important.

One of the primary reasons that we're involved in this proceeding, Renewable Energy Alaska Project, is transmission reform.

This is true for a number of reasons. First, the pancaking transmission rates that are allowed, as you know, really destroy the economics of all projects let alone renewable projects.

The recent example of the proposed Fire Island 2 is a great example. By the time a willing buyer and willing seller were able to move power in the future from Fire Island to Fairbanks, the price had tripled from a little over 6 cents to more than 20 cents a kilowatt hour. Nobody is going to want to invest in an area that has that kind of rule.

Second, out a more robust grid to integration of variable renewable resources like wind can be more challenging. In the Lower 48 in the last 15 years there have been 60,000 megawatts of new wind installed; 60,000 megawatts with no energy storage, none. It's all because the grid is robust and the grid is flexible. The flexibility in that grid is what allows 60,000 megawatts of wind to be installed in the Lower 48 with no storage. So we need a more robust grid.

This leads to a third related

point. With at least four balancing areas in the grid now, we are moving in the exact opposite direction of what we need to be moving in. We have about a half-million people. We have a 600-megawatt average annual load. We need one balancing area, not more balancing areas. The more islanding and balancing areas that we have, the harder it is for renewable energy or any other energy to move where it needs to go when it needs to be there.

So the decision by our Board of Directors, which is 21 folks, was not made lightly. We had a Public Policy Committee working for over eight months on this issue before we brought it to the Board. The result was a resolution that contained the principles that we would hope would be used in developing an ISO, and we've already previously submitted those to the Commission.

We do understand, though, this kind of change represents a big deal for the Railbelt. This is a big change and change is never easy; however, we would argue that waiting to change is only going to make it more difficult in the future and more expensive.

We also understand that asking the Commission to develop an ISO and then regulate it is a heavy lift for an organization that is already understaffed and underfunded. You folks need the help to do this. We just want to say that we would be there; REAP would be there as an advocate to ask that the Commission receive all the authority, funding, and the staff necessary to accomplish the task of bringing order to the transmission grid and leveling the playing field for renewable energy.

We don't have an economist to juggle all the assumptions and to come out with the exact amount of benefits and costs for the Railbelt; however, we believe that the benefit of a universal transmission tariff is self-evident. Renewable energy projects must be able to compete on a level playing field. The cost of generating renewable energy through new technologies, like solar and wind, are continuing to increase so much that we can't ignore them.

Wind is already a price parity in many parts of the United States. Last year in

the midwest the average large wind project came in at under 3 cents a kilowatt hour power purchase agreement. Under 3 cents. So that's price parity already. We can't ignore that.

So we can't afford to box out flat price renewable energy resources with antiquated transmission rules, nor can we afford to be inefficient with the way we move power up and down the grid. We really appreciate all the time and effort that you folks have put into this issue.

We are looking forward to a recommendation to the Legislature that includes creating a central operator for the grid that can make necessary reforms and help chart a more predictable course for our energy future here in the Railbelt.

So we really appreciate all of the work you've done. Thank you.

CHAIRMAN PICKETT: Thank you, Chris.

Is there anyone else in the Anchorage audience who would care to address the Commission this morning?

I will go back to those listening

online. Does anyone online care to address the Commission?

Hearing none, we will close out agenda item No. 1, public participation.

Agenda item No. 2 is I-15-001: In the matter of the evaluation of the operation and regulation of the Alaska Railbelt Electric Transmission System.

Just a couple of comments here. I want to thank everyone. We have received a tremendous number of comments in the past, you know, week and a half or so. They will find their way into the I docket record so you can search them more easily there. We will be having another public meeting a week from today to continue this discussion and work towards finalization of our recommendation.

Just a head's up, I'll be making a decision by the end of this week as to whether or not I'll be calling another special public meeting on Monday the 29th. We've kind of opened the door a little bit. We're going to have another presentation next -- the 24th, next Wednesday, and I had indicated everything's going to be shut down on the 17th;

but given the nature of this and sort of the iterations, we want to have the best record possible as we make this recommendation to the Legislature.

So, again, I know it's been time consuming for you; it's been a lot of effort; but thank you for your participation.

That will close agenda item No. 2.

Agenda item No. 3 is a presentation and report from Chugach Electric Association, Inc., evaluation of options regarding the creation of an independent system operator or similar structure for electric utilities in the Railbelt.

We have Mark Johnson from Chugach Electric with us and Dr. Carl Peterson from NERA economic consultants.

So I will turn it over to Mark at this point.

MR. JOHNSON: Thank you, Mr. Chairman. I appreciate -- I thought I was going to be doing introductions, but you beat me to the punch. I appreciate that.

What we wanted to do -- first of

all, Chugach really appreciates the Commission's time. We know that you've invested an enormous amount of your time and energy and resources into this project, and we've been participants from the beginning. I'll say at the outset that Chugach takes responsibility for proposing the appropriation to the Legislature. We think it's a good idea to examine alternatives for improving the electric grid and the functionality of the grid here in the Railbelt.

We've been encouraged by all the work that has -- that the Commission has taken and other parties have invested in the project. The thing that -- we have invested our own time and energy into it, and one of the things that we did do is we did engage Dr. Peterson through NERA. He's appeared in front of the Commission before. He's an economist by training and education.

NERA, along with Dr. Peterson and Mr. Fraser, prepared a report that was submitted into the I docket record a couple of weeks ago. If you haven't seen it, I would strongly urge you to take a look at it. It is

a matter of record at this point.

I would mention that the assumptions that underlie the report are in the back. It's complete. The data is there for you to analyze, for you to see what NERA did to analyze the options that are before the Commission in the I docket. We would invite questions. We believe that the work is sound and does a good job of summarizing the potential benefits that could accrue to ratepayers in the Railbelt.

So what we wanted to do this morning is Dr. Peterson wanted to spend, I think his target was about 30 minutes, to go through at a high level and describe the nature of the report and its conclusions. We would welcome, greatly welcome questions from the Commission regarding the conclusions that are reached and the recommendations that are made.

So, with that, I'll turn it over to Dr. Carl Peterson.

DR. PETERSON: Thank you, Mark.

Mr. Chairman, Commissioners, I appreciate the opportunity to come to speak with you today about an issue I believe is

critical to the future of the Alaska electric industry. As Mark mentioned, we were engaged by Chugach to look at potential options and the value of those options, and our conclusions are found in the report that Mark pointed out.

What I will do today is give you a high-level overview of what the results were. I'll walk you through how we thought about analyzing the options, the actual options that we analyzed, and then the results from the base case. I will also talk a little bit about the sensitivity or scenario analysis that we did to see how sensitive our results were to various alternative scenarios.

So as Mark said, I'll try to keep this to 20 minutes to a half-an-hour. Then hopefully we can have a good discussion after that. So that's the overview that I just talked about.

I will have a short response to some analysis that's been done over the last couple of months. I believe you've had several presentations and reports that have been presented to you. I will give a brief response to that. That, of course, is not included in

the report that we filed.

I've also included in this presentation a summary of a comparison of key assumptions between the reports that you've seen and our report. Of course that, of course, is not included in the report. So there's a little bit of extra data in this presentation that will give you a little more rounded view of how to interpret the results of our study.

So before we start I wanted to be on a common page for terminology. We've heard the term ISO or independent system operator already today. That term is really a term of art that came out of the discussions that the Federal Energy Regulatory Commission had in the early 1990s when they went through essentially the same process that you're going through right now. So the independent system operator is a not-for-profit entity that operates the grid and operates the dispatch of generation on the grid with some settlement arrangements, some trading arrangements.

We've chosen to use the term unified system operator. That is to identify a

key difference between the Lower 48 and Alaska. We believe that the Alaskan Railbelt system is too small to really have the kind of complex trading arrangements that the ISO through FERC's authority and through decisions have implemented. Largely what I'm talking about is short-term and medium-term markets for electricity and for other products that are associated with the electric system.

So our unified system operator concept is essentially the ISO concept less the complex trading arrangements that we see in the Lower 48. So when I use the term USO or uniform system -- unified system operator, that's what I'm referring to.

The other terminology that's important for understanding our report is the term Transco. By Transco we mean a transmission-only utility. That utility would be tasked with the responsibility for planning and development of the system as a whole; in other words, the entire area that the Transco serves. In this context it would be the entire Railbelt.

So with that terminology we can

walk right into the approach. In looking at the presentations that you've seen over the last few months, at least two months here, we believe that that fairly identifies the kind of key issues as to why an integrated approach might be a good way of thinking about it; but I wanted to just quickly go through that to explain to you why we took the approach we took.

So why evaluate integrated options as opposed to some other approach. Well, transmission investment often results in regional benefits; that is, benefits that go beyond a single transmission utility or a single utility. However, the costs associated with those investments and the risks associated with those investments are really borne by the utility making the investment. This creates a disconnect, as it were, between those risks of investment and the benefits or the larger regional benefits that are associated -- often associated with transmission investment.

That creates a disincentive for investment. That's kind of the key issue that we've identified here in Alaska, that there --

the State of Alaska, the ratepayers of Alaska, we believe, are paying too much for their electricity over the long term. Part of that problem is related to this disincentive for investment, this disincentive to plan and invest on a regional basis.

So we chose to take a look at the costs associated and the benefits associated with creating a more integrated system, and then compare those costs and benefits to doing nothing. So how did we go about doing that?

Well, I've got four bullet points here. The first two I'll talk about on this slide, and the last two I'll go into a little more detail, which is kind of the basic story of the report.

The first thing we needed to do was identify the opportunity that might be here. Why would we do reform? What's the point of reform? We've basically identified three major areas where we think there's opportunity. The first one, which is the key benefit that we've actually quantified in this report, is the out-of-merit dispatch costs. These are the costs associated with generating

electricity on a moment-by-moment or hour-by-hour basis. We believe that those costs right now are higher than otherwise would be the case.

So we've engaged this process to try to identify and quantify what those out-of-merit costs are. Basically what I'm saying here is an out-of-merit generating unit is one that's dispatched when it has a little higher cost than another one that might be able to be dispatched. So we've been able to quantify those using a common model.

The other two benefits which we really have not quantified, although they're true benefits, are benefits associated with planning. So we asked the question: Is the transmission system built to achieve the lowest cost in the long term for Railbelt consumers?

Then there are other benefits associated with, for example, reliability. There are wider economic benefits. We've already heard this morning some discussion of environmental benefits, some discussion of being able to integrate renewable power into the grid much easier -- in a much easier

fashion, and those benefits exist as well. There are other benefits that I'll talk about as well.

So we have not actually quantified those benefits in this approach, but I think -- so you can -- my view of this is you can take this approach as kind of a conservative estimate of the benefits that we believe are there from greater coordination of the transmission system.

So that's how we defined the opportunity that might be there. We had to set out a criteria by which we judge how we -- these different reform options. Basically what we've done is we've quantified the net redispatch benefits for each option; that is, as the option is put into place, how more efficiently can the generation system operate and can we quantify those benefits? Then we identified some qualitative benefits, and there are also benefits that could be quantified, but we did not quantify in this particular study.

So that's the basis for the study. We then had to develop some specific reform options to study, and we had to evaluate

those reform options against the criteria that I just laid out. So I want to go into those last two bullet points in a little more detail.

The first one is: What reform options did we consider? We considered five possible options. The first one, of course, is the control case, that is, the status quo. This is where all utilities continue to plan and invest for their system, and energy is roughly exchanged in the same pattern as it is today. So that's the control option.

The second option is a voluntary exchange option. This is where, again, much like option 1 all utilities continue to plan and invest for their systems, but there are these voluntary bilateral agreements between utilities for exchange of energy on a more efficient basis where that's possible. I just want to make it clear that option 2 is available today and it isn't happening, at least to the extent that it could happen, and so option 2 is kind of a theoretical option. It's a slow movement toward a more coordinated system, but one that we think is nearly theoretical at this point.

Options 3, 4, and 5 begin to change the business structure of the transmission system. So option 3 is implementing a USO model only. So investment is coordinated by this independent not-for-profit organization much like the ISO, but we don't believe there would be the necessity for short-term spot markets. Of course the USO would also coordinate economic dispatch of generation resources. Utilities would still maintain control over their investment. So option 3 is moving towards a uniform dispatch entity.

Options 4 and 5 overlay on top of that a new transmission entity. We call this the Transco. So transmission assets are transferred to a for-profit utility that would be then separate from the existing utility. So you would have in some sense a T utility, and then the other utilities would remain the G and D, as it were.

So the Transco would operate the system subject to the USO protocols, and it would invest in the physical assets of the system; but in option 4 we've included that

USO as part of the Transco. So in some sense it's independent, but it's actually a department of the utility.

In option 5 we've separated that USO out, and we've made it an independent entity. So it's completely independent of the Transco. It's not a department of the Transco itself.

So these are the options under consideration in the report. We believe that these options do generate enough discussion around the future possible structure of the industry to make it a viable cost-benefit analysis. So here's a summary of our results.

The top table gives the results relative to the status quo. These are in net present value dollars for 2015. We looked out over a 50-year planning horizon. As you can see, option 2, which is our largely theoretical option, this is the status quo, but we've allowed these new bilateral agreements; even under that option, even just moving to a bilateral market, the benefits are pretty substantial in 2015 dollars. About $240 million.

Establishing a USO -- this is option 3 -- increases the benefits substantially. The reason is -- the reason there's a major difference between option 2 and option 3 is the USO essentially requires the economic dispatch of generation. So in some sense it squeezes out all those inefficiencies that might exist in a pure bilateral market. That's where we get the $581 million in net present value benefit.

Option 4 and option 5, you'll notice, have the exact same benefit of a little over three quarters of a billion dollars in benefit over these 50 years. The reason is we've modeled option 4 and 5 exactly the same way. We've said: You squeeze out all the inefficiencies in the current dispatch through using the USO, but you also allow the Transco to make regional decisions on investment in the transmission system, which then allows more efficiencies in the dispatch of generation that wouldn't be there under an option 3 only approach.

So the real difference between option 4 and option 5 is really how you think

about including the USO or the ISO as part of the transmission company. We believe there is the potential for a conflict of interest if you include the USO as part of the Transco, and of course that conflict would be avoided if you separated the ISO out and made it a separate entity.

The bottom graph just gives you the results graphically. So that's the summary of our results.

Now, how did we get there? What are the costs and benefits that we looked at in arriving at these net present value costs? So option 1, of course, there are no additional costs because we're not doing anything different, but there are also no additional benefits.

Option 2, we do believe there's going to have to be some transmission upgrades. I think you've gone through these upgrades in previous presentations. These are the Southcentral transmission upgrades. Obviously some approach, some methodology would have to be put in place to get those transmission upgrades; but assuming that happens, those are

the costs that we included and we believe that on an annual basis that would save about $16 million. So if you take that out over the 50 years, you discount it back to today, that's where we get the net present value that we saw in the previous slide.

Option 3, of course we would have the option 2 costs plus you'd have the cost of the establishment of the USO. There are some one-time costs that are associated with that, and then there are some ongoing costs that are associated with that. Although we do believe that those ongoing costs can be reduced by transferring some current utility personnel to this new entity. So it's not like you're completely taking this -- creating this out of whole cloth. You will be using some personnel that are currently in utilities.

The benefits to that, again, it's a reduction in the dispatch costs. We've estimated that at about $40 million annually, again, looking at that over the 50 years and discounting it back to today we get the values that we saw in the previous slide.

Option 4 and 5, we think the

costs of option 2 and option 3 will have to be included in that as well. So you'll have to establish this USO, but you also have to establish a Transco. Similar to the USO, there will be some one-time costs associated with that, which we've used Chugach estimates to figure out what those costs are. There will be some operations costs ongoing. Of course, again, you would probably transfer some current utility personnel to this new entity so that will save some ongoing costs, but there will be some additional operations costs.

We also included the costs of two additional major transmission projects, the Kenai and the Northern projects. Again, the benefits are the reduction in costs. Depending on what year you assume those transmission projects go into place, we've estimated that it's anywhere between $40 million annually in dispatch cost savings up to $126 million annually after the new transmission projects are put into place.

So the costs and benefits that I've just talked about in this table are derived in Tables 5-2, 5-3, and 5-4 in the

report.

So how do we interpret these results that I've just talked about? Well, the largest net present value benefit is for options 4 and 5. This is creating the Transco, allowing the Transco to invest on a regional basis, make decisions, and avoid that disincentive to investment that we talked about earlier. The ratio of the net present value cost -- benefits to cost is over 2; so you're getting about twice as many benefits as the costs. As I mentioned earlier, we modeled option 4 and option 5 is exactly the same way, so that's why we got the same benefits.

So the real question of whether 4 or 5 is the better one is what you think about that conflict of interest that might exist if you included the USO as part of the Transco, and that's what I said earlier.

Now, option 4 is not impossible to implement. It has been done in other places, but we do believe there's an inherent conflict that would exist between the two business units, because in option 4 the USO and the Transco would be different business units

of the same entity.

The problem arises in the following way: When you're starting to plan and decide about investments, the Transco if it had the USO as part of it, it might lead that combined entity to prefer transmission solutions to generation solutions. We don't want that. What we want is we'd rather have the solution be the least cost solution. So if the solution happens to be putting new generation, well, then that ought to be the solution. If the solution is put in more transmission, well, that ought to be the solution. So we think there probably is a conflict of interest here that could be resolved by simply separating those entities.

If you do include those entities as part of the Transco, this would put additional burdens on top of the burdens you've heard about already today that would exist in this new world for the RCA. Essentially the RCA would have to discover and try to prevent these conflicts.

I worked at a regulatory agency for the first ten years of my career. I

understand how difficult it is to extract that type of information from utilities. So we believe that puts an extra burden on the RCA that really doesn't need to be there.

Option 3 has substantial benefits at a relatively low cost, but it does assume that you'd find some process to get those Southcentral transmission upgrades. Option 3, of course, is just the USO only.

As I mentioned earlier, option 2, while clearly cost beneficial, any time you wring those inefficiencies out of the system, you're going to get benefits; we think that seems unlikely to occur because I guess the question is: Why hasn't it already? And we think that even if it did occur for a certain amount of time, it could kind of easily collapse back into the status quo, and that's the real concern with option 2. So we believe option 2 is kind of more of a theoretical option than a real option.

So those are the quantified benefits that we looked at in this kind of meta study, I suppose; and by that I mean what we did is we took information from various

studies, put them together to try to answer a new question.

What we weren't able to quantify were some of these other benefits. For example, we know that there's a direct relationship between increasing the strength of the transmission system and the reduction of the frequency of unscheduled outages. Outages, as the Commission has seen in previous presentations, are incredibly expensive to consumers.

Not only they're expensive to consumers that exist on the system today, they're also expensive in terms of opportunities. So when new businesses want to come to a new area, they want to know that they'll have access to reliable supplies of energy. If you don't have reliable supplies of energy, you'll never see those businesses show up. So those won't show up on any quantitative analysis, because they never showed up in the state. So that's a big concern. We weren't able to quantify those in this study, but we know from other studies around the world and around the United States that those benefits

can be and are substantial.

There's also the issue of resiliency. So what resiliency is is this ability of the grid to sustain changing conditions. Those may be physical conditions; those may be technological conditions; those may be economic conditions.

So, for example, how do we minimize the rate impact or the economic impact of the failure of major machines on the system? How do we take advantage of, for example, new load opportunities? Is the grid resilient enough to take advantage of new load opportunities, or even new technological opportunities? As we heard today, there are technologies that are being tried out around the world in the renewable power sector, and we want to be able to take advantage of those when they're cost effective and when they benefit consumers.

So this resiliency value that we believe comes from a stronger transmission grid, we weren't really able to quantify that, but we believe those are real benefits.

So all of this leads to new

economic opportunity, not just from the direct construction jobs. Of course, if you build new infrastructure, there's going to be an economic impact, but we believe that there is more of an economic impact from creating a more resilient and a stronger grid.

So the last few slides are my response to other analysis, what I've called the Scott reports, and these are documented and I've gone through the documents of presentations to the RCA that were made in April and May of this year. I don't have any strong objection to either the economic insights or the physical, you know, system insights in these reports in these presentations. I generally agree with them. I think they do a good job of laying out the fundamentals. In fact, a lot of what our report does that I haven't talked about goes back through those fundamentals. You'll see a lot of that repeated in our report that you've seen before.

I think there is one area that we have a little bit of a disagreement with, and I'll also talk about areas where we agree.

That's really on these technical parameters. Now, in Appendix 2 to this presentation I've given you a matrix that shows the differences between the assumptions of the technical parameters between the two reports. In my view there are some other differences, but there are really two that stand out to me.

One is the load forecasts. It appears that the load forecast is lower in the high and base case relative to our report. The GVEA load forecasts seem to discount possible future increases in load. We've actually gone through and looked at that as a different scenario, and that's reported in Appendix 1 and also in our report.

It also appears that the gas prices that are used, at least in the extreme cases, are a little bit higher at the Cook Inlet and a little bit lower in Fairbanks. All of this is going to reduce the benefit. Obviously when you have more load, you have more opportunity to reduce the cost of serving that load. So if the load forecasts are a little bit lower, you're going to get lower benefits from these types of studies.

The same is true for the gas prices. If the gas prices are a little bit -- if you think about the ratio of the price of gas from Fairbanks to Cook Inlet, if that ratio starts to get a little bit lower, you get a different set of benefits than you would from ours. So those are the kind of technical parameters or assumptions that I think we see a difference.

Now, do these differences matter? I guess that's the real question you have. The answer is: To some extent, of course, they do. You will get different overall numbers; but from my reading of the reports and from my intuition understanding how these models work, this is really a matter of degree. We're not saying that there isn't a benefit; it's just a matter of how much of the benefit actually is there. You can see those identified in Appendix 2.

Where might we agree? I think we agree that the biggest gains are made from a more robust infrastructure. We believe that a more robust infrastructure, the benefits are fairly robust to any outcome that might happen.

Basically what that means is even though you've got some transmission investment you're going to have to undertake, we don't think that transmission investment is going to be a burden to consumers. It could be a big boon. It could be substantial; but even if the assumptions don't quite turn out the way we think, we don't think it's going to be a big down-side problem.

We believe that greater transmission provides improved reliability. So I think we all agree on that. We also agree that Alaska is different than the Lower 48. You know, just allowing for the trading of energy has not led to least cost dispatch here like it largely had in the Lower 48. You know, if you think about how transmission is justified in the Lower 48, it's almost always justified on reliability basis. The benefits from least cost dispatch are generally fairly small, because it's already being done.

We also agree that Alaska is different in the sense that we don't need these complex trading arrangements. We think the market is small enough, unlikely to be

competitive, and so those complex trading arrangements really are probably unnecessary, and a cost basis, least cost dispatch is probably the way to go.

Again, production costs are not the entire story. I think we agree on that. There are other benefits, and in some sense transmission investment provides a hedge against unforeseen things in the future. It's kind of like: We didn't evaluate this. We didn't actually quantify the value of that option, but that option is there. Part of it, again, we heard earlier today. The option to take advantage of new technology such as renewable technologies. That will not be there if these changes, if these reforms are not made. Those benefits could be substantial, especially when we're talking about over a 40- or a 50-year planning horizon.

So, in conclusion, Alaska's leaving money on the table. Ratepayers are paying unnecessary costs. I think that's one conclusion you can make from our study. We believe a movement towards a USO or a USO/Transco model would reduce production

costs. We believe it would increase the right type of investment; in some sense optimal investment. We believe that it would create a stronger, more resilient, more reliable grid which then promotes a stronger economy in Alaska. Again, production costs are only part of that story. These other benefits are substantial. They're real. You can't ignore them; but the production costs alone, as we've seen, are substantial. The production cost savings can be substantial.

The last slide shows the appendices, and I think at this point I'll open it up and if we have questions, I'm happy to respond. Thank you.

CHAIRMAN PICKETT: Commissioner questions of Dr. Peterson?

Commissioner Patch.

COMMISSIONER PATCH: Dr. Peterson, thank you very much for being here. When I saw your name on the report, I recollected you'd been here.

DR. PETERSON: I have.

COMMISSIONER PATCH: I went and found some of your testimony and reread it.

Thank you for your work. Like much of the work that has been done, it's both interesting and challenging.

If the Commission responds in the affirmative to the legislative charge, would an ISO or similar structure be of general benefit to Alaska ratepayers, what is your specific recommendation regarding the first step we should take?

DR. PETERSON: I think the first step you need to take is identify how the transaction would -- how the transition would actually work. There's going to be a lot of work you're going to have to do to make this work. There's a lot of details that we haven't gone over in this report, though I've given you a checklist of the types of issues that you'll need to address.

So I think the first step would be to identify that transition, have a transition plan. Figure out: What are the things we need to do from a practical perspective. You know, how are we going to, say, move -- if you're going to create the Transco, which we think is the right way to go,

how are you going to move the assets from the existing utilities in? These are issues that are going to have to be worked out, and they're detailed issues. So I think the first step is to create that stakeholder process to work through those issues.

COMMISSIONER PATCH: Should I understand, then, from your response that you think the Transco would be the first step after some process and discussion of steps that should be taken along the whole roadway?

DR. PETERSON: I think the Transco should be the goal. I think there are intermediate steps that you're going to need to take, and those intermediate steps are to identify how you're going to actually create that entity. I think it's probably a little bit easier to set up an ISO, although there are lots of issues that need to be addressed there. So in some sense this work can be done concurrently. So the practical issues of setting up the ISO and the practical issues of setting up the Transco can be identified through the stakeholder process together; but I think the overriding goal ought to be moving

towards a Transco entity.

COMMISSIONER PATCH: So can I then also conclude that one other point of agreement you have with Dr. Scott and perhaps a point of agreement you have with Mr. Rose -- thank you for your testimony, sir -- is that a very small agency like this facing a very complex problem is in need of resources and staffing?

DR. PETERSON: I have to agree with that.

COMMISSIONER PATCH: Thank you very much.

DR. PETERSON: I have to agree with that.

CHAIRMAN PICKETT: Are there other Commissioner questions at this point?

I have a few, but I'll turn to my fellow Commissioners. Commissioner McAlpine, did you have anything you wanted to --

COMMISSIONER McALPINE: If I may, Doctor, do the benefits derived from the ISO or USO/Transco, are they dependent upon the investments in the transmission system?

DR. PETERSON: Some of them are,

yes. So what we did was we looked at the least cost dispatch benefits of essentially an existing transmission system, and that's how we identified the benefits of the USO. Then we asked the question: What types of transmission could be unleashed if you went to a Transco model? So we've looked at the studies that have been done previous here in Alaska, and we identified those. We said: If those are done, if this new business model allows for those investments, then what additional efficiencies can we wring out of the system? So, yes, some of the benefits are in fact closely associated with new investment.

COMMISSIONER McALPINE: And have you analyzed in today's dollars what the amount of that investment would be?

DR. PETERSON: Yes. In fact, what we did is we looked at the previous studies that have been done from the Railbelt. As I said earlier, we did essentially a meta study. So we looked at data that was previously -- from studies that were previously done. I'm trying to remember the name of these studies, but we've identified the studies in

the report, and we've taken the costs that are associated with those investments directly from those studies. They are actually identified in the -- what we call the derivation tables. I think I have those -- if you go back to slide -- yeah, right here at the bottom. Those costs and benefits are derived in Tables 5-2, 5-3, and 5-4. So you can see the actual transmission investment in those tables.

COMMISSIONER McALPINE: And do you know off the top whether those transmission investments, if you subtract that from the savings that are to be achieved with the development of an ISO/USO/Transco, do the costs exceed the savings or --

DR. PETERSON: No, it's the other way around. The savings exceed the costs.

COMMISSIONER McALPINE: Okay. And by what amount?

DR. PETERSON: I think we had a 2.0 benefit to cost ratio. About twice.

COMMISSIONER McALPINE: Okay. The reason I ask -- a little analogy here. My wife was looking at the newspaper and she said: Oh, look, if I buy this, I can save $35. I

took the page and I said: If you buy this, you can save another 70; if you buy this, you can safe another hundred; if you buy everything on the page, you've saved a hell of a lot of money when really you've only spent a lot of money.

DR. PETERSON: Right, right.

COMMISSIONER McALPINE: And my concern right now is with the level of generation capacity that we have in the Railbelt, that the ratepayers are going to be asking the question: Why have we allowed all of this stuff to be built? And to go to the ratepayers, if you were to do that, and ask the question: Do you want to invest additional money in transmission? I think it's going to be a tough sell.

DR. PETERSON: That's actually why we did the cost-benefit analysis the way we did. That's a fair point, a very good point, very economic point, and one that needed to be addressed. That's why we did it this way. We looked at: What are the new costs? Not just the transmission investments, because there's going to be costs associated with creating the USO and the Transco itself. So we had to

include those costs as well. So all of the costs that are associated with these new entities are included in our cost-benefit analysis. Then we compare those costs to the benefits, and that's where we got the 2.0 ratio at least for options 4 and 5.

COMMISSIONER McALPINE: Thank you.

CHAIRMAN PICKETT: Commissioner Rokeberg.

COMMISSIONER ROKEBERG: Thank you, Mr. Chairman.

Good morning, Dr. Peterson.

DR. PETERSON: Good morning.

COMMISSIONER ROKEBERG: Let's see. On your net present value calculation you set the years in 2015. What was the cap rate you used, or the percentage rate?

DR. PETERSON: You're talking about the discount rate?

COMMISSIONER ROKEBERG: The discount rate.

DR. PETERSON: Yeah, we used a real 5 percent discount rate.

COMMISSIONER ROKEBERG: On page

11 you made a comment about: Conversely the current disaggregation of the Railbelt is expected to reduce reliability.

Could you explain that statement in a little more depth?

DR. PETERSON: The way I interpret that statement is that when you have a disaggregated investment structure like you have today, almost by necessity the transmission system will not be as resilient and reliable as it could be. So what I'm doing is I'm comparing the idea of creating a new, more integrated transmission system with the existing -- and comparing that to the existing structure. So that's where we get the idea that today's structure is almost required to be less reliable than a more integrated structure.

COMMISSIONER ROKEBERG: And in determining the investments, did you utilize the EPS, so-called pre-Watana, whatever numbers? I know on your page 6 you're using an investment in options 4 and 5 of 811 million NPV costs.

DR. PETERSON: That's right. We derived those numbers from what we call the AEA

report, and that was the pre/post-Watana transmission study from March of last year.

COMMISSIONER ROKEBERG: So your references throughout your notes regarding like the completion of the Kenai Southern portions and the northern portions are reflective of the recommendations of that particular study?

DR. PETERSON: That's correct.

COMMISSIONER ROKEBERG: So you didn't analyze that or make any --

DR. PETERSON: No. As I said earlier, what we did was we did a meta study. So we took results from previous studies, and we took results from -- we didn't do the production cost modeling either. We took results from the production cost modeling. Of course we had input on, you know, what the assumptions ought to be and how we interpret them, but we took all of these different data points and put them together to try to answer the question that we asked in this particular report.

COMMISSIONER ROKEBERG: Well, they made some conclusions about benefits and savings. Did you do your own analysis as to

verify theirs, or did you use their numbers?

DR. PETERSON: We used our own benefit numbers that were based on the modeling that was done by Slater Consulting, and then we compared it to their costs. So in effect we did our own benefit-to-cost analysis.

COMMISSIONER ROKEBERG: So you concluded in the main that they were accurate?

DR. PETERSON: We concluded that under almost any scenario -- there is one scenario, if you look at the last -- I think it's Appendix 1, which is actually in the report as well, we did these different six cases and 11 scenarios for those six cases. I think this will show up in Table 8-9, so it's actually the last table. You'll see under one scenario, that's scenario 11, where there's significant loss of load and there's LNG at North Pole. Options 4 and 5 actually become slightly cost not beneficial. The numbers are basically 1 to 1, but the benefit-to-cost ratio is slightly below 1. Not enough for my spreadsheet to actually have it show up under 1, but it actually would be slightly below 1; but under all the other scenarios we found

these to be cost beneficial.

COMMISSIONER ROKEBERG: Is that why you mention that you had a difference with Dr. Scott in terms of the load factors in the GVEA --

DR. PETERSON: Right. These all have to -- these have to do with the load forecasts and the gas prices themselves. That's why we get the varying responses we get in these last set of tables from Table 8 to the one we just talked about.

COMMISSIONER ROKEBERG: And you brought up the LNG prices. There seems to be a pretty big delta between the two reports. Actually the 17.60 it looks like one -- more consistent with one that came out of this room a year or so ago -- but there's been substantial changes in facts regarding the Interior energy project.

Did you take any of those new circumstances into account while looking at it, or how did you determine the delta in the LNG price in Fairbanks?

DR. PETERSON: So we relied on local intelligence for those prices, and of

course those prices are then embedded in the production cost modeling, which was done by the Slater group.

COMMISSIONER ROKEBERG: Excuse me. Local intelligence?

DR. PETERSON: Local intelligence.

COMMISSIONER ROKEBERG: Could you explain that?

DR. PETERSON: Well, as you mentioned, the facts change on the ground, and so we have to depend on the expertise on the ground since, you know, I'm not here every day. So that's -- in consultations with the utilities here, mostly Chugach, and in consultations with the production cost modeling team, we came to the conclusions that are embedded in this Appendix 2 data.

COMMISSIONER ROKEBERG: Kind of in a nutshell, could you tell me as a result of those differences, what were -- how did it affect your conclusions in any way?

DR. PETERSON: Well, I mentioned that earlier, but it's worth repeating, though.

So the question is: Do these

assumptions really matter? The answer is: Yes, they have some impact on the benefit analysis. Of course if you have higher-cost gas at Cook Inlet and lower-cost gas in Fairbanks, you don't have as much opportunity to reduce the costs. If you have higher-load forecasts, you have more opportunity to reduce the cost. So they definitely will have an impact on the results.

But what we decided and what we've found is that it's really a matter of degree and not a matter of existence; in other words, the benefits exist. It's just a matter of how big they are. That's why we also did the scenario analysis that we did that we just talked about is to try to test various assumptions, not just the load growth and the gas prices, but various assumptions to -- and various investment categories to determine whether these results are really robust. We found that they are.

COMMISSIONER ROKEBERG: As I recollect, in the EPS or what you call the AEA study, they relied a great deal on reliability to justify the looping or parallel routes both

from the south and the north. In your study you indicated that you gave no weight to reliability or you didn't quantify that?

DR. PETERSON: Well, yeah. It's not that we gave no weight to it; we just didn't quantify it. It actually is very typical to justify transmission investment on reliability benefits. But we also realized that because of the unique situation you have in Alaska, there are also these dispatch benefits that are probably more substantial here than in other places around the country and perhaps even around the world.

COMMISSIONER ROKEBERG: So your 2.0 cost-benefit ratio is based mostly on dispatch vis-a-vis other elements?

DR. PETERSON: That's correct. Yeah, these are all on -- the benefits, at least, are related to how much you reduce the overall production costs in the region as a result of different --

COMMISSIONER ROKEBERG: But there seems to be -- is that because of the Transco/USO establishment for a more economic or more beneficial dispatch vis-a-vis --

DR. PETERSON: That's exactly right.

COMMISSIONER ROKEBERG: -- just the construction of more redundant, more reliable transmission, or is it --

DR. PETERSON: That's both.

COMMISSIONER ROKEBERG: -- under the EPS plan.

DR. PETERSON: It's both in the sense that when you have this new transmission, you have access to being able to least cost dispatch generation, but we did not take the benefits of, say, looping per se into account. We only took the benefits into account as they affect the dispatch of generation.

COMMISSIONER ROKEBERG: Very good. Thank you very much.

CHAIRMAN PICKETT: I have a few questions, and then Commissioner Wilson will close out the questions. She has a very calming persona, and that's kind of a nice way to end the proceedings here.

I'm convinced that the status quo is not acceptable and that bilateral agreements will not get us there. I'd like to start with

just some of my observations on the transmission element and then go into generation and then talk about governance of potential structures.

DR. PETERSON: Okay.

CHAIRMAN PICKETT: I find myself sort of in the position that I imagine some of the FERC Commissioners were thinking in the mid '90s to the late '90s. You know, the concerns about the pancaking transmission rates across the different geographic areas and the free rider problems, which over time have become kind of embedded in the system and don't address physics and how stuff actually works necessarily.

In the Alaska context I think I'm concerned about the lack of a discernable financing mechanism for a transmission project that will cross several CPCN areas of utilities and is fairly substantial in price. I don't see the State stepping in. I don't see the ability of any of the utilities collectively to do something like that. I've certainly seen no evidence of that in last few years on this Commission.

That leads into the reliability issue. I realize there's voluntary reliability standards, and we have had comments from those that say: Stand down. It's perfectly under control. I read the standards, and I see that elements of them don't get enforced. If you don't have standards that have enforceability, you don't have standards.

Now, that's another whole set of issues there and how you get there, but those are sort of the things that are driving my thinking at this point in time. I've spent a lot of time looking at ISOs and RTOs in the Lower 48. In fact, I just got back from Houston spending some time with ERCOT folks.

I think it's important, whatever the Commission ultimately determines, to make it very clear that these entities are operating in totally restructured markets for all -- and I think ERCOT's probably one of the purest competitive, and it's brutal; it is brutal, but highly effective in terms of price discovery market, and it's very different than anything we've been talking about up here. And that makes sense. I mean, that's a $40 billion

market. We're less than a billion for the Railbelt. It's just not practical to think that we're going to end up at that type of a place.

But I do think there's some lessons learned from the initial formation of ERCOT. You know, when it sort of started off, it was very different than how it looks today. I think the one thing that appeals to me, kind of this overarching observation, is it's a very transparent marketplace. They disclose a lot of stuff on their website all the time. You don't get to hide-the-ball thing you've got going on up here. Their governance structure to me appears to be much more sound than those in PJM or CAL ISO or whatever just in terms of getting the buy-in from a pretty wide range of stakeholders that, you know, prior to the formation were sort of at each other's throats a lot of the time.

There's a trust element. I think we cannot discount that given the history up here. You've got to have the trust element or this thing is going to have some real challenges. So just in terms of the

transmission element and my observations on governance, would you care to say anything or weigh in?

DR. PETERSON: I'm not sure I could have said it any better. I completely agree with you. I think that -- you know, as I was mentioning earlier, I think the first steps you have to take is to create that process that will begin to then create a little bit more trust.

I think part of the problem that you have with trust is you don't have the transparency that a lot of these new business models and markets are actually creating. Transparency creates trust. If you can create a transparent stakeholder process, that will be -- that will then give people the ability to begin to trust each other. There's no question.

I was involved in some of the initial discussions in creating what used to be called the Midwest ISO. I'm from Chicago. Commonwealth Edison was one of the largest entities and wanted to push for the creation of this Midwest ISO; but there just wasn't the

trust with the various stakeholders. They ended up leaving, going to PJM, and MISO was then created in a different state with a different set of stakeholders. That was a difficult process, but I think creating that process, it's going to be -- there's no question it's going to be difficult to begin with, but I think creating that stakeholder process has got to be the first step.

But having said that, I mean, the other thing that you may have an advantage over FERC is you can take the leadership role. You can take that role on and as a Commission say: Look, we're going to do this. Get together, figure it out. If you need our help, we're here. If you need something addressed that isn't being addressed, we can step in; but otherwise we're going to create this stakeholder process that's going to create the transparency that eventually is going to be to get you to the point where you need to be.

CHAIRMAN PICKETT: And my final comment slash question deals with the whole generation issue we have that's sort of unique, what's transpired in the last few years, and

the fact that in reality the Commission, outside of after-the-fact approval of depreciation studies and things of this nature and incorporating them into the revenue requirement, has really nothing to do with pulling the trigger on the decision to create large-scale generation with the exception of Chugach, which came in for preapproval for a lot of other reasons.

In statute the utilities are guaranteed a rate that will allow the repayment of the debt on those assets whether those assets run or not. Those are just -- that's the simple -- whether we've got overcapacity or whatever, that's just the lay of the land that we have. I've heard presentations, we had one a couple weeks ago that was pretty good on some voluntary potential efforts, but my fear is out-of-merit dispatch of these generation assets will be closer to the norm than not if the status quo continues. That does impact the pocketbooks of ratepayers, and they will pay more than they necessarily have to, we will burn more natural gas than we necessarily have to, and all of those types of things. But you

can see we have a lot of new, very attractive, well-designed, well-engineered generation plants in the Railbelt, and they're not all online yet and more to come.

So there's going to be -- we have co-ops that are the dominant form of utility with a municipality. So the decisions that have been made, it's going to be sort of hard, I think, for some of these utilities to fully buy into economic dispatch in an open and transparent way. I guess, talk me off the ledge here.

DR. PETERSON: Well, I mean, that's not all that different than we had in the early/mid-1990s in the Lower 48. A lot of states even to this day have not completely restructured their markets. You know, Texas, as you mentioned, is kind of the extreme case, but places like Wisconsin, Indiana, even Michigan, which kind of restructured its market, really don't have restructured markets. We had -- prior to the 1990s, generation was built by individual entities. There's no question that the network was beginning to become the network that we think of it today.

Not maybe as resilient as it is today, but it certainly was in its infancy.

A lot of companies, like the one in my home state, Commonwealth Edison, made some decisions about generation that, you know, a Commissioner in 1991 in Illinois might say the exact same thing you just said. They built a lot of generation. They built it under a regulatory compact that guarantees the recovery. What can we do about it?

Well, part of what we're saying is, and part of what this analysis does is it says: Well, you have a set of generating units. They are what they are. We're not planning for the generation in this model. But what we are doing is saying: Once you have that set of units, how do you use them in the best way you possibly can? We're not suggesting that that existing capital isn't going to be recovered. It will continue to be recovered through rates as it was before.

But the question is: How do you get that marginal cost into line with what it ought to be? That's really what we're talking about. So, yes, there was a lot of frightened

utilities in the mid and early 1990s. They were scared that they weren't going to get cost recovery for generation that they had built maybe even just a few years before that, you know, that had 50-, 60-, 70-year lives in some cases.

But I think if we focus on what we're trying to do here and we focus on the benefits that come from greater interconnection and greater coordination, that should be the focus; and I think folks will begin to understand the benefits to their own ratepayers and to their own utilities.

CHAIRMAN PICKETT: So the message to all the utilities in the room, you will get rate recovery on your generation.

DR. PETERSON: That's the regulatory compact, yeah.

CHAIRMAN PICKETT: And it's clearly embodied in the Alaska statute. I do appreciate the work that you've done on looking at the modeling that we have worked with Dr. Scott on. You know, we had some particular requests of him to lay out a wide variety of scenarios, because, quite frankly, I'm

skeptical about modeling, but it is a useful tool. Nobody was modeling a year ago as to what actually happened with hydrocarbon prices effectively with any credibility anyway. That's the challenge of modeling.

DR. PETERSON: Right, right.

CHAIRMAN PICKETT: But, again, I appreciate very much you being here and thank you.

I will turn it over to Commissioner Wilson to close out Commissioner questions.

COMMISSIONER WILSON: Thank you. I don't want to end on a down note, so I will ask my -- this question first and then move on to more optimistic questions.

Did you look at any costs and benefits, particularly benefits, in the light of possible decrease in population thereby decreasing electric demand? Did you look at any of the down sides?

DR. PETERSON: We did have scenarios where we had significant loss of load. Now, why that load goes down is kind irrelevant to the model. It's just a matter

of, you know, it going down. Whether it went down because you've lost a major, say, gold mine or something like that or a major industrial --

COMMISSIONER WILSON: Well, I notice there is a case where you do lose the Fort Knox gold mine.

DR. PETERSON: Right, right, right. But we didn't -- and if you're asking was there a scenario where we said we lose the gold mine and part of the reason we lost the gold mine is because people are leaving the state and oil prices are low and all of those things, we didn't have that in particular as a scenario; but we did have reductions in demand as one of the scenarios.

COMMISSIONER WILSON: From a logical perspective, the benefits that you gain from economic dispatch, et cetera in the Transco/USO would be diminished by decreased electric demand or it's not that straightforward?

DR. PETERSON: Let me answer that in two different ways. It's somewhat straightforward in this sense: If you are

serving less load, there's less opportunity to reduce the cost of that load. However, even if you have less load, the benefits associated with reliability, the benefits associated with resiliency, the benefits associated with integrating new entities, such as renewable into the system, the benefits associated with the economic development to the extent that those are there, those would not necessarily be diminished.

COMMISSIONER WILSON: I'd like to go to your option 2. I had kind of a difficult time understanding option 2. If you look at page 22 of the report, what I understood from your presentation today is that option 2 includes some system upgrades, which I didn't really get from this explanation of option 2 on page 22. So I'm just wondering if you could explain what underlies the savings that you would see in option 2.

DR. PETERSON: So option 2 -- it might be best to just go ahead and go back to -- here we go. So option 2 is the voluntary exchange. So what happens here is we have the status quo on the business model. That is, all

utilities continue to plan and invest for their own system, but we allow for voluntary bilateral agreements between utilities. So what option 2 -- option 2 really isn't an invest-in option. Option 2 is really an option where we -- from a modeling perspective, what we've done is we've lowered the hurdle rate for the trading. So when you lower the hurdle rate between utilities for trading, they'll end up trading a little bit more.

Now, how you actually -- you know, what level you do that at, how you actually model that, you know, that's a question; but what we wanted to get at was if we could in some way convince the utilities to enter into these new voluntary agreements and do a little more trading, a little bit more trading, which will then create a better dispatch, it won't be as good as option 3, but it will be a better dispatch than option 1. That's where the benefits from option 2 arise.

COMMISSIONER WILSON: And how would this encouragement -- how would you envision this encouragement taking place?

DR. PETERSON: You could stand up

and pound on the table. Yeah, that's kind of -- that's kind of the problem that I identified at the beginning, that option 2 is really somewhat theoretical for a couple of reasons.

First, how do you get utilities to trade that should have the incentive to do it today, but don't? And once that occurs, how do you get them to continue to do that? My concern with option 2 is that whatever mechanism you use -- and we didn't evaluate a mechanism because that would be hard -- I'm not quite sure how you would do it. I'd have to think about it. But whatever mechanism you use to create that new voluntary exchange, that's going to have to be put in place for a long period of time. If it's not, you're going to collapse back to option 1 again, and that's our real concern with option 2.

COMMISSIONER WILSON: Okay. I think what confused me about option 2 was your slide 7 where under costs you list Southcentral Transmission Upgrades. So that seemed to imply that option 2 was more than simply voluntary agreements.

DR. PETERSON: If you look on Table 5-2, we actually do have some transmission investment in option 2. That's on page -- I guess the page number didn't come through -- it would be page 38. So these tables, these 5-2 -- these are the tables that I've cited at the bottom of the slide, by the way.

COMMISSIONER WILSON: Okay, yes.

DR. PETERSON: So these are the derivations of the costs and benefits. So you can see what's included in each of the cost-benefits analysis from these tables. We did include some Southcentral transmission upgrades in this Table 2, which also allows for some greater flexibility in trading. So you can see there's about $20 million of investment.

COMMISSIONER WILSON: Total over 2016 and 2017?

DR. PETERSON: In total, right. That's correct. That's correct.

COMMISSIONER WILSON: They're very near-term investments.

DR. PETERSON: Very near-term

investments, correct.

COMMISSIONER WILSON: But you don't have -- you can't identify what those would be?

DR. PETERSON: Yeah, off the top of my head I couldn't, but they are identified in the --

COMMISSIONER WILSON: In another table somewhere?

DR. PETERSON: Well, in the report itself. I can get those for you and cite those for you.

MR. JOHNSON: I believe they're -- I've seen them elsewhere, I think, in the report, but they're -- Fossil Creek is one of those facilities, and there's another project that would bring immediate improvement in the ability to trade and otherwise conduct commerce over the net.

COMMISSIONER WILSON: Okay. Thank you.

Now I'd like to talk about the status quo. How do we know what the status quo is? The status quo really sort of began on May 1st when MEA began to be self-generating. So

we have a brand new status quo, and it will continue to evolve as we put our last generation plant online in 2016. That's the ML&P Plant 2A. So in answer to a question from Commissioner Rokeberg, you said that it just makes sense that disaggregation will lead to less reliability and less resiliency. But on page 18 of the report, if you look at the first paragraph under 2.33, the second to the last sentence, it reads: "Absent some type of reform, it is likely that the reliability degradation that has been seen since disaggregation began will continue to deteriorate and even accelerate."

So I'm just wondering where the information comes from. Is that just an assumption, or is that fact based? It says the degradation -- reliability degradation that has been seen. So what that implies is that there's actually documented degradation and reliability.

DR. PETERSON: This particular section is in response to discussions we've had with personnel at Chugach. They've explained some of the situation that we have. Though

having said that, we're not all that surprised given the situation that you would begin to see liability get somewhat worse due to the disaggregated nature of the transmission planning. So I don't have any specific studies that I'm citing to there. That's mostly in response to discussions we've had with folks here in Alaska. I'm sure Chugach could probably give you a better discussion of that.

COMMISSIONER WILSON: And that's part of your basis for believing that option 1 is not a good option to adopt?

DR. PETERSON: That's correct. Though having said that, when we heard those, it didn't create cognitive dissonance, right. I mean, it made sense that we were hearing the things that we were hearing.

COMMISSIONER WILSON: And is that due in part to more load balancing areas, more --

DR. PETERSON: That's part of what we mean by disaggregation, but it also has to do with the control of the system itself.

COMMISSIONER WILSON: So control areas.

DR. PETERSON: More control areas gives you a little bit less -- interestingly enough, a little bit less control over the entire system.

Mark has pointed out: We did identify a couple of situations. Like, for example, I believe on page 16 we talk about the situation with the submarine cables and what happens when you disaggregate and you lose load; you no longer have the incentive to invest in those systems, but you also have a less incentive to keep them up as well. So it's not just a long-term problem that's being created; it's also a shorter-term problem. So that's identified on page 16 and 17.

COMMISSIONER WILSON: Thank you. That's all I have for now.

DR. PETERSON: Okay.

CHAIRMAN PICKETT: So we'd like to thank you on behalf of the Commission for being here this morning, Mr. Johnson and Dr. Peterson. It's been helpful to us. Thanks again. With that, I will close out agenda item No. 3.

Agenda item No. 4 is other

business. I have no other business to come before the Commission this morning. Do any of the Commissioners?

I will close out agenda item No. 4.

Agenda item No. 5: Does the Attorney General require an executive session?

MR. GOERING: No.

CHAIRMAN PICKETT: Agenda item No. 5 is closed.

Is there a motion to adjourn at 10:40 a.m.?

COMMISSIONER PATCH: So moved.

CHAIRMAN PICKETT: Second?

COMMISSIONER WILSON: Second.

CHAIRMAN PICKETT: All those in favor say aye.

COMMISSIONERS: Aye.

CHAIRMAN PICKETT: Thank you all in the hearing room and online who have participated this morning.

(Off record - 10:40 a.m.)

TRANSCRIBER'S CERTIFICATE

I, Leslie J. Knisley, hereby certify that the foregoing pages numbered 3 through 83 are a true, accurate, and complete transcript of the Public Meeting of the Regulatory Commission of Alaska, held on June 17, 2015, transcribed by me from a copy of the electronic sound recording to the best of my knowledge and ability.

_____ _____

Date Leslie J. Knisley, Transcriber

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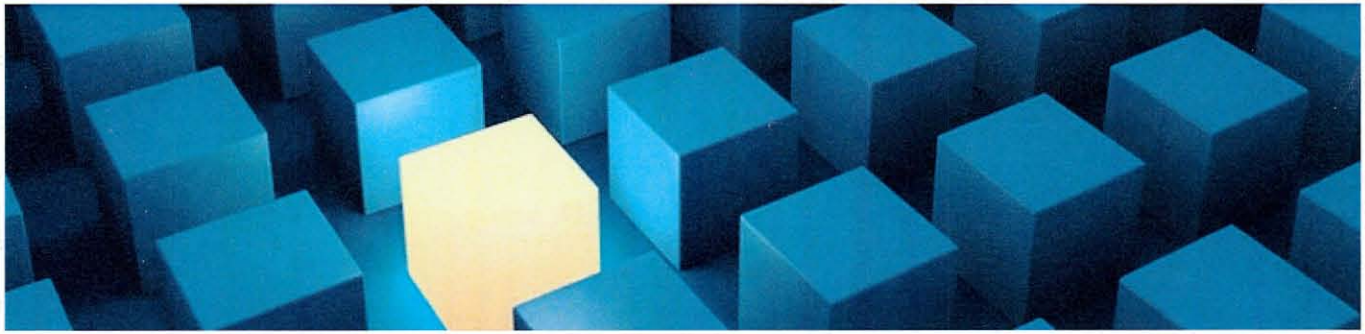

Evaluation of Options Regarding the Creation of an Independent System Operator for the Railbelt: A Report in Response to Docket I-15-001

Carl Peterson

Special Consultant

Regulatory Commission of Alaska

June 17, 2015

Insight in Economics™

Overview

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- Some terminology
- Approach taken to the analysis
- Options under consideration
- Summary of results
- Benefits unquantified by analysis
- Response to other analysis
- Conclusion

Terminology

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- **Unified System Operator ("USO")**: Entity that would operate common system-wide security-constrained economic dispatch with post-dispatch financial settlement. The USO would create planning protocols and reliability standards.
  - This differs slightly from an **Independent System Operator ("ISO")** in that it would not operate complex trading arrangements such as day ahead and other procurement arrangements
- **Transco**: a transmission-only utility tasked with the responsibility for both area-wide and inter-area transmission planning and development, and field operations and maintenance of transmission assets. Transmission investment would be made in accordance with the USO planning protocols and subject to RCA prudence review and pre-approval.

Approach

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- **Why evaluate integrated options?**
  - Transmission investment often results in regional benefits
  - Transmission costs, however, accrue only to the utility making the investment
  - This disconnect between who takes the risks of the investment and who benefits from the investment creates an investment disincentive
- We chose to look at the costs and benefits of creating a more integrated system and compare that to the costs and benefits of doing nothing

Approach (Continued)

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- Define the opportunity;
  - ***Out of Merit Dispatch Costs***: the cost of generating electricity to meet the needs of Alaskan consumers, from the existing set of generators, is higher than it could be.
  - ***Planning***: Is the transmission system built to achieve the lowest long-term total of Railbelt transmission investment plus electricity generation costs.
  - ***Other benefits:*** reliability, wider economic benefits, environmental benefits and other
- Set out criteria by which reform options should be evaluated;
  - Quantify re-dispatch (net) benefits of each option
  - Identify qualitative or non-quantified benefits
- Develop specific reform options;
- Evaluate the reform options against the criteria established in order to identify the best option.

Reform Options Under Consideration

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Option	Description
Option 1: Status quo	All utilities continue to plan and invest for own systems and energy is exchanged in the same pattern as today
Option 2: Voluntary Exchange	All utilities continue to plan and invest for own systems; voluntary bilateral agreements between utilities where possible
Option 3: USO Model	Investment is coordinated by a non-for-profit independent entity responsible for reliability coordination and economic dispatch of generation resources. Utilities maintain control over investment.
Option 4: Combined USO-Transco	Transmission assets transferred to a for-profit company that is separate from existing utilities. Transco operates and invests in the physical assets and contains the USO.
Option 5: Transco and Separate USO	Same as Option 4 with USO a separate entity.

Summary of Results
NPV in $2015 over 50 Years

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Option No.	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Option Name	Status Quo	Status Quo + New Bilateral Agreements between Utilities where Possible	Establish a USO	Combined USO and Transmission Company	Separate USO and Transmission Company
NPV Gross Benefits ($m	-	$259	$640	$1,603	$1,603
NPV Costs ($m)	-	$18	$58	$811	$811
NPV Net Benefits ($m)	-	**$240**	**$581**	**$792**	**$792**
NPV Ratio	-	14.2	11.0	2.0	2.0
Comment	This is the do nothing option	Benefits might be difficult or impossible to achieve in practice	Central transmission upgrades assumed	Option contains potential conflict of interest	Potential conflict of interest avoided, compared to Option 4

Cost and Benefits

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Option	Costs	Benefits
Option 1:	No Additional Costs	No Additional Benefits
Option 2:	South Central Transmission Upgrades	Reduction of Dispatch Costs due to improved trading (≈ $16.1m annually)
Option 3:	Option 2 plus Establishment of USO less transfer of personnel for USO	Reduction of Dispatch Costs due to centralized dispatch (≈ $40m annually)
Option 4 and 5:	Option 3 plus Transco Establishment + Operation less transfer of personnel plus Kenai transmission projects plus Northern projects	Reduction of Dispatch Costs due to centralized dispatch (≈ $40m annually up to $126m annually after new transmission projects)

Costs and Benefits are derived in Tables 5-2, 5-3 and 5-4, NERA Report

Interpretation of Results

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- Largest net benefits, NPV $792 million in 2015 dollars, are achieved in Option 4 and Option 5.
- The ratio of NPV costs to NPV benefits is 2.0 for these options.
- Option 4 and Option 5 are modeled to be identical from a quantitative analysis perspective
- Option 4 involves the USO and Transco being part of a single company – with the USO business unit being not-for-profit and the Transco business unit being for-profit.

Interpretation of Results

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- Option 4, while not impossible to implement, is less preferred to Option 5
- An inherent conflict of interest would exist between the two business units, where the for-profit Transco would tend to benefit from USO decisions regarding reliability standards and planning arrangements which resulted in attractive Transco investment opportunities. This leads the combined entity to prefer transmission solutions even to a lower cost generation solution
- This puts an additional burden on the RCA to discover and prevent these conflicts

Interpretation of Results

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- Option 3 has a substantial benefit at relatively low cost but does assume that a process can be found to undertake the south central transmission upgrades
- Option 2, while cost beneficial, seems unlikely to occur since it has not already occurred and could easily collapse into the status quo.

Unquantified Benefits

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- There is a direct relationship between increasing the strength of the transmission system and reducing the frequency of unscheduled consumer outages. Conversely the current disaggregation of the Railbelt can be expected to reduce reliability.

- Resiliency is the ability of the Grid to sustain or weather changing conditions either economic or technical.
  - minimize the economic rate impact of an unexpected failure of a major generator or transmission
  - having sufficient transmission and generating capability to take advantage of new load opportunities

- All of this leads to new economic opportunity not just from construction but from improved infrastructure

Response to Other Analysis

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- The "Scott Reports" as documented in the presentations made to the RCA in April and May provide an excellent starting point.
- I have reviewed each of these and generally agree with the economics and policy insight. Much of the discussion is also contained in our report.
- One area of disagreement is on "technical parameters" of modeling (See Appendix 2)
  - Load forecasts: Load is lower in High and Base Case relative to NERA report. GVEA load forecasts seem to discount possible increases in load
  - Gas prices at Cook Inlet are higher but LNG lower at Fairbanks

Response to "Scott Reports"

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- Do differences matter? To a certain extent yes, **but only** to the degree of benefit not to the existence of a benefit (Appendix 2)

- Where might we agree?
  - Biggest gains are from more robust infrastructure (Policy Discussion, 5/20/2015, p. 5; Figure 1-1, p. 7 NERA Report)
  - More transmission not likely to be a burden (Policy Discussion, 5/20/2015, p. 5; also see Scenario analysis in Appendix 1, and Tables 8-2 through 8-9 NERA Report)
  - Greater transmission provides improved reliability (Policy Discussion, 5/20/2015, p. 5; pp.46-47 NERA Report)
  - Alaska is different than lower-48
    - Just "allowing" trading of energy has not led to least-cost dispatch
    - Complex trading arrangements are not, however, necessary to move Alaska toward least-cost production

- Production costs are not the entire story other benefits from expanded transmission investment provide a "hedge" against changes in fuel prices and load growth

Conclusion

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- Alaska is leaving money on the table and ratepayers are paying unnecessary costs
- A movement toward a USO or a USO/Transco would:
  - Reduce production costs
  - Increase investment
  - Create a stronger grid and a stronger Alaska
- Production costs are only one part of the story the reliability and other benefits should not be ignored

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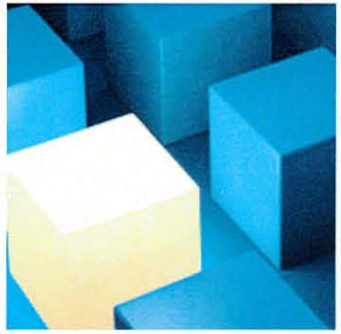

Appendix 1: Scenario Analysis

Production Costs by Scenario and Case

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Scenario	Case 1 Data Changes + High Hurdles between all 5 pools	Case 2 Case 1 + Central Transmission Upgrades + 3 Pools (GVEA, Central, HEA), Low Hurdles between GVEA and Central	Case 3 Case 1 + Central Transmission Upgrades + 3 Pools (GVEA, Central, HEA), Low Hurdles between all pools	Case 4 Case 2 + 2 Pools (Central/North, HEA), Hurdles between 2 pools	Case 5 Case 4 + Northern Transmission Upgrades, NPCC economic	Case 6 Case 5 + Southern Transmission Upgrades (Single Pool)
1. Base Scenario	473,354	457,236	462,044	433,497	369,401	346,466
2. LNG at North Pole	414,556	397,963	N/A	381,495	362,925	347,462
3. Retire Old Coal - (Aurora/Healy 1)	540,886	528,800	N/A	486,688	416,022	366,862
4. LNG + Retire Old Coal	478,374	451,503	N/A	410,290	390,242	367,503
5. Increase GVEA Load: 100 MW peak, 60 MW off-peak	N/A	N/A	N/A	N/A	487,224	436,121
6. LNG + Increase GVEA Load	588,664	562,448	N/A	513,429	462,141	435,513
7. Retire Old Coal + Increase GVEA Load	N/A	N/A	N/A	N/A	542,058	463,561
8. LNG + Retire Old Coal + Increase GVEA Load	665,545	641,352	N/A	595,321	521,739	461,115
9. Base + Oil at $55/bbl in 2015	422,801	399,763	392,714	381,785	361,134	347,260
10. Scenario 1 + Fort Knox closes (loss of 44 MW in every hour)	423,443	403,815	N/A	393,705	322,765	309,170
11. Scenario 2 + Fort Knox closes (loss of 44 MW in every hour)	369,221	352,755	N/A	341,934	321,969	309,325

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Appendix 2: Comparison of Assumptions

Comparison of Assumptions

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		UAF-RCA Studies									NERA Studies								
		Base Case			Lowest Benefit Case Sensitivity 3			Highest Benefit Case Sensitivity S5			Base Case			Lowest Benefit Case Scenario 11			Highest Benefit Case Scenario 8		
		A-1	B-2	Benefit	A-1	B-2	Benefit	A-1	B-2	Benefit	Case 1	Case 6	Benefit	Case 1	Case 6	Benefit	Case 1	Case 6	Benefit
Data Item																			
Study Year		2020	2020		2020	2020		2020	2020		2020	2020		2020	2020		2020	2020	
Annual Loads (including distribution losses)	GWh																		
- Railbelt		4968.0	4968.0		4968.0	4968.0		4968.0	4968.0		5274.3	5274.3		4887.8	4887.8		6060.0	6060.0	
- GVEA		1130.1	1130.1		1130.1	1130.1		1130.1	1130.1		1436.4	1436.4		1050.0	1050.0		2222.1	2222.1	
- MEA		849.2	849.2		849.2	849.2		849.2	849.2		849.2	849.2		849.2	849.2		849.2	849.2	
- ML&P		1167.6	1167.6		1167.6	1167.6		1167.6	1167.6		1167.6	1167.6		1167.6	1167.6		1167.6	1167.6	
- CEA + SES		1329.1	1329.1		1329.1	1329.1		1329.1	1329.1		1329.1	1329.1		1329.1	1329.1		1329.1	1329.1	
- HEA		491.9	491.9		491.9	491.9		491.9	491.9		491.9	491.9		491.9	491.9		491.9	491.9	
Additional Annual Transmission Losses	Approx. GWh	98.7	87.1		97.7	88.9		107.6	96.6		111.6	93.1		93.6	70.1		207.5	124.9	
Cook Inlet Nat. Gas Price (delviered)-Summer	$/mmBTU	9.41	9.41		7.39	7.39		7.39	7.39		8.90	8.90		8.90	8.90		8.90	8.90	
-Winter	$/mmBTU	10.11	10.11		8.09	8.09		8.09	8.09		8.90	8.90		8.90	8.90		8.90	8.90	
Fairbanks Liquid Fuel Price (delivered)	$/mmBTU	25.34	25.34					25.34	25.34		35.21	35.21		35.21	35.21		35.21	35.21	
Fairbanks LNG - Price (delivered) -Summer	$/mmBTU				11.57	11.57								17.60	17.60		17.60	17.60	
-Winter	$/mmBTU				12.27	12.27								17.60	17.60		17.60	17.60	
- Used by NPCC					Yes	Yes								Yes	Yes		Yes	Yes	
- Used by NP CTs					Yes	Yes								Yes	Yes		Yes	Yes	
- Used by Zehnder CTs					Yes	Yes								No	No		No	No	
Coal Price - Aurora (delivered)	$/MWh	67.93	67.93		67.93	67.93		Retired prior to 2020			67.93	67.93		67.93	67.93		Retired prior to 2020		
- Healy 1 (delivered)	$/mmBTU	2.88	2.88		2.88	2.88		Retired prior to 2020			2.88	2.88		2.88	2.88		Retired prior to 2020		
- Healy 2 (delivered)	$/mmBTU	3.31	3.31		3.31	3.31		3.31	3.31		3.31	3.31		3.31	3.31		3.31	3.31	
Variable Production Costs	$ millions	415.9	336.4	79.5	313.8	280.8	33.1	390.5	292.6	97.9	473.4	346.5	126.9	369.2	309.3	59.9	665.5	461.1	204.4

Sensitivity 3: Low Gas Prices, LNG at Fairbanks
Sensitivity S5: Low Gas Prices, Retirement of Old Coal

Old Coal: Aurora - nominal retirement 12/31/2025
Healy 1 - nominal retirement 12/31/2032

Scenario 11: LNG at North Pole, Loss of Fort Knox load
Scenario 8: LNG at North Pole, Retirement of Old Coal, Increased Load in GVEA

Old Coal: Aurora - nominal retirement 12/31/2025
Healy 1 - nominal retirement 12/31/2032

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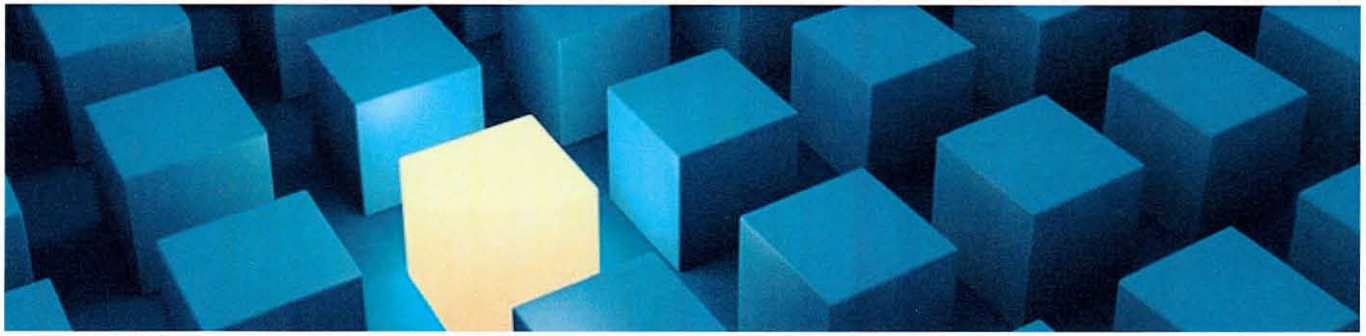

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STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners: Robert M. Pickett, Chairman
Stephen McAlpine
T. W. Patch
Norman Rokeberg
Janis W. Wilson

REGULATORY COMMISSION OF ALASKA
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501

PUBLIC MEETING
June 24, 2015
9:00 a.m.

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P R O C E E D I N G S

(On record - 9:00 a.m.)

CHAIRMAN PICKETT: Good morning. This is a public meeting of the Regulatory Commission of Alaska. It's Wednesday, June 24th, 2015. It's 9:00 a.m. With me on the dais are Commissioners T. W. Patch, Commissioner Stephen McAlpine, and Commissioner Janis Wilson. And we are expecting Commissioner Norman Rokeberg to join us shortly.

The first agenda item is public participation. If anyone would care to address the Commission this morning either in the east hearing room or online, please keep your comments to no more than five minutes.

Is there anyone in Anchorage who would care to address the Commission this morning? Seeing none, I will go to those online.

Is there anyone online who would care to address the Commission? Hearing none, I will go back to our Anchorage audience. One more chance. Any desire to address the Commission?

MS. BANNER: I'm from -- I'm from the Valley. I'm not from Anchorage.

CHAIRMAN PICKETT: Okay. Anyone

Thank you, Mr. Chairman.

CHAIRMAN PICKETT: That will close out agenda item number three. And we'll move on to agenda item number four, I-15-001, in the matter of the evaluation of the operation and regulation of the Alaska Railbelt electric transmission system.

Just an update as to where the Commission is, we will have a public meeting on Monday, the 28th of June, in which the Commission's recommendation to the Legislature will be announced. I have been in contact with the chief of staff for Speaker Chenault's office to let them know timing-wise and procedurally what they can expect as far as format. And it's a pretty extensive record at this point. But we will be providing a six- to seven-page summary letter of the Commission's determination with a couple thousand page pdf that incorporates all the various elements that we have been working with for the last year. I had a personal meeting with Senate President Kevin Meyer and informed him pretty much of the same thing.

So that is all I have on agenda item number four at this point. And we'll move on to agenda item number five, a presentation by Homer

Electric, generation resources with Mikel Salzetti and Mr. Day. So please proceed at your convenience.

MR. DAY: Thank you very much, Commissioners and Chairman Pickett, for giving us this opportunity. We really appreciate the opportunity to just kind of address some things we've heard throughout this docket. I'll be talking about a couple of items, and then Mike will be following me a little later through the presentation. We'd invite you to ask questions if there's something significant as we go through this. But by all means we're here to answer any questions you might have at the end of the presentation.

I will try to mention the page numbers for the benefit of those people online so that they can stay on track with us. And right now I've got page number 1, which is just simply the title page. And if we move on to page number 2, I want to give you a little background on who I am. I've been in front of this Commission, but I think it's the first time I've addressed the new Commissioner McAlpine. Welcome.

But I've been in the Alaska energy business

here in mainly Anchorage and down on the Kenai for the last 38 years. I apologize, I was here for Order 19 but my memory gets a little vague about those things. So I don't know the full docket number. But that was the order that decided to draw some boundary lines between Chugach and ML&P.

Back in the days when I was first here, we had a pretty rollicking good time in terms of each party trying to say, you know: That's our territory; This is our territory. And the Commission finally entered in and said: Let's have a little definition here. I was here for the construction of the -- what we call the Alaskan Intertie. That's the Anchorage/Fairbanks Intertie. And I was one of the key members in development of the data interchange where for the first time the utilities started exchanging realtime data between their control centers so that we could see what was going on on this interconnected system.

I was president of ML&P when Bradley Lake was just a gleam in some engineer's eye that said, yeah, we got to build a power plant down there in Kachemak Bay. And we've seen that come to fruition. I've seen most all the interties and

interconnections built that we've put in Alaska in the last many years. And, as I've mentioned, I've worked for ML&P and MEA. And throughout that I've worked with the other utilities. So a lot of stuff. I'd like to say I've lived through most all of the attempts to join the utilities together. So I have a little history there.

But be that as it may, on page -- or presentation -- sorry -- on page 3, we've heard a lot of things through this docket, and there's a couple of things I want to emphasize a little more. I personally feel that some of the significant items were glossed over. And I felt like, not that the Commission was given bad information but may have misheard something or misinterpreted some things.

So I'd like to present at least our view on some of these issues that have been before you in this docket. And my example is I could talk to you all day about how good cherry pie and ice cream is when it's fresh from the oven. You might know about it. But until you really have it, then you understand it.

And one of my compatriots suggested a different quote. One from Mark Twain that says,

"A man who carries a cat by the tail learns something that he can learn in no other way." And I've had a few cherry pies in my life and through my career here that includes trying to carry a cat by the tail.

So here are the four things: Generation overbuild. I've heard the Commission talk about that. I'd like to address some of the things I hear in there. Firm power -- and even this came up in Mr. Keen's presentation about what is this firm power. And I'd like to restate what I see as the generation guy's view of firm power and talk a little bit about utility cooperation.

Of all the things that I put on that first -- or slide number 2, a lot of them represented voluntary cooperation. Some of them represented enforced cooperation. But the utilities have throughout the years done a lot of things to cooperate. And then my partner here will talk about our proposal or our idea of a gas co-op.

So on slide number 5, are generation resources overbuilt? And we went out and looked at the FERC forms and took everybody's installed capacity in the 2014 system peak. And you can see the numbers up there. But if you look at the line

or the column marked "capacity," you see our installed capacity right around 2000. Our system peak -- and that has an asterisk by it because that is not the system coincidental peak -- that's a harder number to come up with -- but it's simply the addition of each utility's individual peak. And they may occur at slightly different times. So that's the engineer's distinction between a system coincident peak and just simply the addition of everybody's peak.

So there's a lot of capacity. 1,058 MW, which represents really 180 percent of excess capacity on the Railbelt. And that breaks down across the various utilities. And apologies to Seward, but I couldn't find their data in time to put them on here. But they're relatively small in comparison to these numbers.

So at first blush, at first look on slide 5 you'd go: Yeah, you've overbuilt. But there's some other things that are of concern to the generation planner on slide number 6; the efficiencies, the long-term effective cost. What is the cost? And I heard very strongly from the consumer from the Valley, you know, the cost of electricity is a big concern. And it is a big

concern to us every day. That's one of those cats you carry by the tail. When we have forces in the marketplace that force us to raise rates, it is a real difficulty for many of our members, many of our consumers. And we recognize that.

But something that's lost or forgotten about is both the peak efficiency and the off-peak efficiency are very important. If you think about it from the standpoint of peak power occurs basically during the Monday through Friday -- the workweek, 9:00 to 5:00 -- that's when the electrical system generates the peak or the most energy. But that's 40 hours in a week and there's 168 total hours in a week.

So less than one fourth of the time you spend in this operation called peak mode. You spend three quarters of your time off peak. So the efficiencies of off peak have, like, three times the value or the impact. You might be really efficient on your peak but terribly inefficient in your off peak. And that's going to really hurt your bottom line. That's going to impact your consumers.

The security issue: It's not like locking the door and keeping the people out of the

generation plant. The security is how reliable is the electric delivery system? And that encompasses the generation resources, the transmission resources, the distribution resources. Because at the end of the day, the consumer who has an outage is out. He's either on or off. And he really doesn't care whether it was a transmission line or distribution line or what caused it. It's an impact to them.

But the utility holds this, what I call a duty to serve. We really do take this seriously, that we need to keep those lights on. And you've got to have sufficient power that is firm. And I may be misusing the FERC definition, but this is my definition. I have to have some security of that power that I'm depending on so that I can keep the lights on for my consumers.

We'll lead to slide number 4. Oops, I'm sorry. I'm looking at the wrong page here. Number 7, contingencies. We have to look at what kind of things can happen to our system so it won't compromise, so that we can continue this duty to serve under most credible events. Now, if we had the world-class earthquake again and everything fell down, you know, I'd have to buy,

you know, a pass on that. Because there's not much I could do to prevent that. But we try to build things so that it's compartmentable. You can segregate the system, and it will still survive; and we can keep the lights on.

A real prime example of this is this recent fire on the Kenai that forced us to open unexpectedly the transmission line between Kenai and Anchorage. And initially you'd think, oh, well, then Kenai is on its own and Anchorage. But Anchorage is separated from its Bradley resource, which is a big economic driver. It really helps hold the costs down in Anchorage and north. So those utilities north of this outage tie line are faced with the problem of running equipment that is --

ONLINE SPEAKER: 18 people on conference --

MR. DAY: -- running equipment that is less efficient. It's more costly to replace the Bradley power, which really helps to hold those costs down. Now, granted, we get the tie line back and they'll still get their power out of Bradley. But there's this opportunistic cost that occurs at the time it occurs. And you can't

rewind the clock. You can't go back and say: Oh, we'll make that gas cheaper, those units more expensive -- or less expensive.

Availability: And this is very much in Mr. Keen's presentation in some of those things. But some resources may not be available during certain times. Winds: You've heard this before, is somewhat intermittent. Solar: Daylight only, or clouds move in or weather. You can impact the input of a solar installation.

Tidal: At least there's a planned period you can look at and say: Okay, we're going to get some power from a tidal resource. And even hydro can be water limited because of seasonal rains or storage capacity. So all of these things play into their less -- they can be less than firm. And we still have that duty to serve.

So moving to slide 8, I want to talk -- go back to the generation resources being overbuilt. In this particular chart we took all of the resources that were built before 1986 -- those mechanical devices that are more than 30 years old -- and redid those numbers. Now, the capacity that's installed that is newer than 30 years old is 939 to serve 852 MW of noncoincident peak,

which means we're about 10 percent overbuilt for new generation.

And you can again look across the various utilities and see that distribution starts to move around a little bit. And we'll talk a little bit about some of the outliers as this becomes more clear.

But I use the metaphor that if you come to my house you'll find I'm kind of a car guy. And I like older cars. You'll find a bunch of cars at my house. But there's not many of them that I'm willing to drive to Anchorage and back on a regular basis because they're old. They've -- they're fun. They're fun to drive around town and they're useful when I need transportation, but they're not something I want to rely on every day. And that's my position on some of these older units.

Now, there's exceptions to some of the older units. The hydro plants usually have a much longer life. Some of the coal plants don't suffer from the degradation of the economic running. They're pretty steady in their costs. But gas turbines do suffer quite a bit from technological obsolescence. So something that was built in the

'70s and '80s is nowhere near as efficient as some of the new, modern aero-derivatives that we've all installed here lately.

So the utility has to address firm power. Must have a firm plan in place to supply power regardless of the kinds of things that we think could probably happen. And probable contingencies must be planned for in advance. And it's part of the process that Homer Electric went through in putting its generation resources together in that -- and, again, going back to the fire, we had taken our mainstay, our economic unit out of service for maintenance that week. And then the fire came along.

And suddenly we were in a position where we did not have our main efficient unit and were forced to rely on Bradley Lake, our new plant at Soldotna, and a backup plant over at Bernice Lake. But that Bernice Lake unit is very expensive to run.

So what we did is we got busy and made a deal with ML&P where they would sell us some power but supply it from Bradley Lake. And many people would say: Well, gosh, down there on the Kenai you've got Bradley Lake. Why can't you just plan

on using that? And, again, the car metaphor. It's kind of a bad idea for me to plan on using my neighbor's car if mine breaks down without kind of making those arrangements in advance. And, after all, it is their resource. It's not our resource. And it's bad planning to plan on that. And it goes back to this duty to serve.

But the duty to serve puts me in a position where I have to run relatively inefficient units in order to meet the load requirements of the customers. But that means an economic stress, a rate impact to our customers.

Moving to slide 10, let's say utility A wants to buy 20 MW of power. B agrees to sell it for $60 a megawatt hour -- and these are just contrived numbers, but they're kind of real world. If utility B has some kind of failure, remember most of -- 90 percent of our generation comes from mechanical gas turbines. And these things are prone to fail. They do fail from time to time. But if they have a failure and can't supply under the ERCOT rules, you would have to purchase from the next less economical or the next step economical producer, say C, at 20 MW.

But if C has a price of 80 MW an hour, then

B, in making this deal, loses $20 every megawatt hour that was part of this deal. Well, guess what? Next time B goes to sell or sell, quote, economic power, they've got to put the risk price on it rather than the production price. And this is one of the differences between firm and non-firm. And the net result I think is that these economic sales decline because the price represents the risk. And firm power and non-firm power is really about the risk and who's going to take the risk and who's going to provide the fix for when things happen.

Moving to slide 11 -- and I'm summarizing here -- what drives us? The utility load projection is really an inexact science. I like to joke that those pesky consumers don't behave. They turn things off and on as they see fit, and we have to respond to it. There's been a lot of attempts to levelize the load or control the load out there. But so far in Alaska I don't think those have met with a lot of success.

We have this duty to serve. And in that is this inherent duty to plan for failures. We've also got to include spinning reserves, which is part of the dilemma of ancillary services, because

you just don't get to put your power into the system. There has to be this backup or spinning reserve that we -- all the utilities share in, because this is part of planning for contingencies, planning for failures.

You must plan for some ready reserves. Again, in our case just recently with the fire, we were taking down our Nikiski unit for necessary repairs. And we had to make sure we had those reserves at the ready so when the fire did take out the transmission line we had a backup plan and could continue to serve.

And then the utilities must also consider a geographical element. There's, you know, the Kenai. There's Anchorage. There's Fairbanks. And those three areas are connected by single transmission lines, which are subject to failure for one reason or another. But the important part is that people's lives and well-being depend on having a source of electricity, of reliable power. And we as utilities really accept that and embrace that.

So going back to the generation resources overbuild -- and in doing this analysis I took those same numbers that we started with at the

beginning, took out everything that's older than 30 years. And then for each utility took out the largest unit at each utility as we experienced last week in the fire. And then looked at how those numbers shape up.

We have very little excess capacity. Can barely squeak by. Now, this isn't to say that in case of a multiple -- major contingency at each one of the utilities we would be unable to serve. We would be. But this would force us to call into these --

CHAIRMAN PICKETT: Excuse me just a minute.

For all of you online, would you please mute your phone.

Please proceed.

MR. DAY: Thank you.

So all of these -- if all of these contingencies were to occur simultaneously -- and that's a fairly unlikely event -- there -- we'd call on this less efficient, older equipment to make up the difference. But that would have an economic impact on the system. So I think we've put together this system so that we can in normal conditions provide power as cheaply as we can,

given today's constraints. And we have kept some of the older equipment in reserve in order to provide that necessary backup.

Moving to slide 13 -- and we're getting close to the end, I promise -- how do utilities cooperate? I mentioned some of these things in my first slide. But we have bimonthly meetings to coordinate maintenance schedules. And we'll probably increase that in the near future because this fire -- and I keep going back to that because it's totally disrupted our construction schedule for the next couple of months. And the summer is like the roads; very busy construction schedule as we try to get things properly prepared and properly repaired and get them in good, solid condition going forward.

Cooperative activities -- and I know the Commission has seen some -- a certain amount of squabbling between the utilities that -- but we've cooperated pretty famously at Bradley Lake for 20, 25 years. We have the Bradley O&D's that has been a mainstay of technical cooperation as well as the Alaskan Intertie -- which is now called the IMC, the Intertie Management Committee -- and the IC -- the Intertie Subcommittee -- that talk about

issues that are true to all utilities. And it's a good place where we share information.

Our dispatch centers communicate daily or hourly especially when there's issues. So we cooperate on an operational level all the time. We have frequent discussions over buying and selling excess power or spin. Prime example, again, is last week we worked a deal with ML&P where we could shut off our very expensive Bernice Lake units and buy this Bradley -- ML&P Bradley power at Bradley. And they were willing to make that deal.

So we have these occasional bilateral short-term contracts. And we do economy energy sales as often as we can. And MEA is now -- we've been talking to them. They're a new player on the block. But interesting, innovative things like figure out how to send HEA's gas to the EGS plant. Let EGS generate and take that power either at Bradley Lake or, you know, deliver it -- we could deliver it to MEA and take MEA's share at Bradley Lake and everybody's a winner. So we do pursue those things on a very regular basis.

And in that regard, this -- I looked at this comment from MEA's comments to this docket that

they just filed just a few days ago. I thought it was just spot on. And you can read it for yourself. But in the middle it talks about it being a testament to the people, the men and women who daily work very hard to keep prices as low as we can and to keep the lights on. And while you probably see a lot of bickering here, you as Commissioners get to notice the dog that barks. The dog that doesn't bark, it's kind of hard to notice.

And I'm here to tell you there's a lot going on behind the scenes where we are cooperating. And just like any family, when there's a little bit of dispute, you've got to appeal to the higher authority and say: We can't solve it. You guys have got to help us.

So with that I thank the Commission and I'll turn it over to my partner, Mike Salzetti. Thank you.

MR. SALZETTI: Thanks, Bob.

You know, one of the largest barriers to economic dispatch on the Railbelt on generation -- we're on slide 15 now. Here we go -- is the volumetric provisions associated with our gas sales and purchase agreements. Basically,

those agreements have hourly, daily, sometimes monthly and certainly annual maximums associated with those. Conversely, we also have monthly and/or annual minimum purchases that we need to make to satisfy those contracts.

And given the variability that Bob just mentioned of storms and fires and unexpected equipment failure, it's pretty tough to manage these gas contracts. And if you throw in energy sales and/or purchases, it gets really difficult to manage through these contracts.

So the first thing I have to do when I'm contemplating an energy sale is, you know, determine if there's excess capacity there. But then I need to know where that gas is going to come from to serve that. Am I going to need to dip into storage? What's that going to cost? How do I price that appropriately? Is it going to push me into peak gas -- swing or peak gas?

And, you know, while I have a pretty good feel for what's going on tomorrow or even this month, I don't know what's going to happen between now and the end of the year. And I have a maximum amount of gas that I can purchase per my contract. And I don't want to necessarily make sales that

could potentially put me at risk of not having gas at the -- at the end of the year to serve my own load.

On the flip side, as Bob said, if we have some sort of abnormal condition, we're going to see what that generation's going to cost us by going through all the same steps. And then we're going to contact some of the other utilities to see if they can sell us energy at a cost less than what we could produce it for ourselves.

But at that same time, I also have to remember that I have some minimum contract requirements that are -- basically, all of these contracts are some form of take or pay. Either, you know, on a monthly or annual basis. And you can wipe out a lot of economic energy sales or economy energy sales if you have to buy gas that you don't use.

So what are the -- if we go to the next slide, slide 16, some of the potential solutions we've looked at, as Bob mentioned, would be having the buying utility supply gas to the selling utility. While we've explored this, to be honest with you, we haven't been successful in pulling it off.

There are postage stamp tariff rates out there on the ENSTAR system in the Kenai Beluga Pipeline system. But the truth of the matter is that we have individual transportation agreements or special contracts with those entities. And they're very specific as to where we can receive and -- where gas is delivered and received on those systems. And so it's difficult to transport that gas to another utility.

And what's even more complex is the fact that, well, not -- the economy energy isn't always with one utility or even with one generation unit within that utility. So while we're trying to pursue that to facilitate economic purchases of power and to manage our gas sales agreements, it's difficult to do.

The other concept we would like to consider is a gas cooperative. And if we jump to the next slide, slide 17, this concept is not without precedent. Back in 2009 we formed the natural gas supply company, which was a co-op of all of the electric utilities on the Railbelt. And really the thought was that by aggregating the natural gas supply needs of several of the utilities, a larger, more reliable and cost-effective supply of

gas could be achieved.

Well, ultimately this group morphed into the long-term gas supply group which included ENSTAR to address what we perceived was an imminent gas shortage through the import of LNG. Really, the concept there, the framework and the model is still very applicable.

The major advantage of a gas co-op is that it would aggregate all of that supply. And it would eliminate those barriers that we just talked about there. Really, the load on the Railbelt is the load on the Railbelt. It's really what units are generating that energy. So if we can get it to the point where we can truly do economic dispatch, then the real savings is that we use less gas.

And so by it aggregating our gas and then eliminating those mins and maxes and the risks associated with that, it would lead most probably to less gas cost overall. But there are additional savings. I think there's some transportation savings to be had. You know, theoretically -- or let's just say, for example, if HEA had a gas contract with a producer that had production off of the ENSTAR system, we'd need to pay an ENSTAR tariff and a Kenai Beluga tariff to

get it down to our Nikiski plant.

Conversely, let's say CEA has a contract with an entity that has production off of the Kenai Beluga Pipeline. Well, they're going to have to pay that KBPL tariff and the ENSTAR tariff to get it up to the Southcentral power plant. If we had an aggregated gas company there, well, then the gas off of the ENSTAR system, that contract would serve gas into the Anchorage basin. And then gas off the Kenai Beluga system would then serve gas to those power plants that are located on the Kenai Beluga Pipeline.

The same is the case with storage. While I'm not privy to the other utilities' injection/withdraw schedules, I'm confident there are days where I'm injecting gas and they're withdrawing gas. So, again, for example, let's say I'm injecting 5 million a day and ML&P is withdrawing 10 million that day, we're both paying those fees. So we're paying a fee equivalent to 15 million a day.

If that storage were aggregated, we would only be required to pay the withdraw fee associated with 5 million or the net associated with that storage. Furthermore, if we studied

that and we achieved some efficiencies, it might be possible that we'd have some excess storage that could be made available to MEA or Golden Valley Electric, which would allow them to have some storage as well as then spreading those costs -- those capacity costs now over five utilities instead of three utilities. It would get us bulk buying power.

It would potentially reduce our regulatory expenses. So if we had a pipeline tariff case like we currently have before the Commission, it wouldn't be four legal teams and four sets of expert witnesses and four regulatory groups. It would be a single entity. There's also probably some labor savings to be had. Quite frankly, you probably wouldn't need as many gas managers as myself negotiating contracts and worrying about the -- protecting the interests of a single utility. It would be the co-op as a whole.

Now, what would it take? Well, really, this would probably take a Railbelt postage stamp transmission tariff. Because just like I have to worry about the costs associated with transporting gas to a different utility to serve me for economy energy sales, I got to get that electricity back.

And so if there were a postage stamp tariff, it would help eliminate those issues associated with the electricity coming back from that gas co-op.

I would also -- you know, one point that's not up there, I would inject, you know, really, this would require some additional study and some modelling to ensure that it truly benefited all of the players that would be associated with this. Lastly, it would take cooperation, not only cooperation amongst the electric co-ops and municipalities, but even cooperation with the producers and transporters. But I think there's some real savings to be had for those -- for those folks as well.

HEA believes that a gas co-op might address a number of the issues associated with economic dispatch, and it warrants further study. We'd like to thank the Commission for this opportunity to present here, and we're happy to take any questions if time allows.

CHAIRMAN PICKETT: We would like to thank you for appearing. And seeing how this is going to be my last regular meeting as chairman, I'm going to abuse the power of the chair and fire away some questions. I'm intrigued by what you

voluntarily are attempting to do on the gas side and even this concept of a gas co-op. But I'm -- I'm a finance numbers guy.

And I start with the assumption that given the current circumstances in the state of Alaska either on the gas side -- outside of the programs and credits that are currently in place -- on the transmission side it's not particularly realistic to expect the Legislature of the State of Alaska in the near term or reasonably midterm is going to have the ability or desire to put a lot of money into this.

So when I look at a gas co-op in which you're aggregating demand and I'm a producer -- and this is pretty standard stuff -- they're concerned about creditworthiness and whoever is signing contracts with them that can actually deliver. So I'm kind of curious as to the -- I realize it's probably very tentative and early. Because the earlier concerns of four years ago didn't materialize so probably it's just a shell at this point.

Is that a correct --

MR. SALZETTI: Sure. It's really just a concept. Although, as I noted with the

natural gas supply company that was formed through NGDA, those were some of the issues that we were working to address. Same thing with a long-term gas supply group. You know, we were looking at a consortium and import of LNG who had all of those same creditworthiness-type concerns.

So, you know, it's not new for us to see those things and to potentially deal with those things. We dealt with them really with CINGSA as well on those same issues.

CHAIRMAN PICKETT: And on the storage -- when you get to the storage and some of the things you're talking about there, it just seems like institutionally with the current utility structure with CINGSA there's a lot of hurdles to get to what, you know, you are proposing. That on the surface sounds pretty easy and everything. But when you get into the nitty-gritty of it, it's going to be a very challenging situation.

And now for Mr. Day. Can't let you get off the hook. You have been involved with Railbelt transmission issues and witnessed a lot of different things. I've only been a Commissioner -- this is my eighth year. But I

have developed a degree of skepticism, I guess, when I hear plans of proposals and reorganization and this and that.

And the thing that strikes me -- I mean, I'm not going to go down the excess generation road, because that all depends on the assumptions. And the generation's in place. The generation is going to be paid for. And the good thing about the generation is it's more efficient, 30, 35 percent, depending on how things actually work out over the generation it's replacing in terms of the amount of natural gas it's burning.

And the utilities were able to go to the financial marketplace at a time where it's -- the interest rates are very, very good. And so I think, you know, 10 years down the road when people look back, though there may have been all this criticism about excess generation, I think it's going to sort of have a little bit different feel to it at that point in time.

But I am concerned about transmission. And, to me, when I look across the Railbelt, the transmission piece is putting it diplomatically in a state of lack of cooperation. I realize Bradley Lake and I realize the Intertie management and all

that kind of stuff. But when I went back and reviewed the EPS study, the pre-Watana, the thing that was striking to me in this 300-page document, there were three references in the 300-page document to funding or financing and it didn't say anything.

There was absolutely nothing in there how to make this $900 million alleged need in transmission to happen. And, in fact, when you drill down to some of the specific projects that had a 23 to 1 cost benefit ratio and you looked at the prices, you could only come to the conclusion either this report is wrong or the utilities are insane for not doing it. And to this day it continues to not be done.

So my concern is with, you know, some aging transmission. And I think there are some very much needed transmission upgrades to the system. When you have a project that crosses two or three utility service areas, I am not convinced the institutional mechanism is there at all to do a substantial project of 100 million, 150 million and get everybody lined up, given where their balance sheets are. I think that's a very dicey proposition.

So talk me off the ledge, Mr. Day.

MR. DAY: Boy, yeah. You've given me a real softball there. Thank you very much. Appreciate that.

Here's kind of the dilemma as I saw it going into this. We had the IRRP. I always mispronounce that thing. The Integrated Resource Regional Plan. But it came about that the timing was kind of bad. There really is a sense of you've got to do something now.

And the reason I approach this overbuild of generation is all the utilities went through that boom time when the oil pipeline was built, and they grew hand over fist. And most all of the equipment was built in the '60s and '70s. And we've relied on that equipment for these many, many years.

And we were coming to a crisis. We had older, less reliable, less efficient equipment. Gas prices were putting a lot of pressure on the utilities to do better because there was, you know, at the time most of these projects were looked at we were thinking about ten to $15 Mcf gas. That was the projection a number of years ago.

And when you look at the costs that we were projecting at that time -- and I admit, nobody has a really good crystal ball; but that's what we were planning for -- and you look at $100 million, $200 million, $300 million to build some transmission lines which might alleviate some of your difficulties, it wouldn't alleviate this economic pressure from the gas.

So many of the utilities made this decision to go with what had been the standard in Alaska for so many years. And that is localized generation so that we have this stand-alone island mentality of reliability and efficiency. And that's what we built.

And even though you can make the case for a $100 million transmission line that might provide some terrific benefits, you couldn't do that in a time frame that got you out of this dilemma that you were in with this old, old equipment that you were dealing with. So it's time to fish or cut bait. And the utilities made this decision to put the efficient generation in and really continued what we'd been operating with before.

I wish, you know, I had a magic wand that could rewind the clock and do some things

differently. But you make decisions at the time that are beneficial. And you can't do all things. You can build your power plant or you can build a transmission line. And as a result we built power plants because that was something we could accomplish.

CHAIRMAN PICKETT: No. I'm not -- you know, at this point what has been done with generation is done. It's baked in the cake. And it will be paid for by the ratepayers. But we know going forward there are going to be needs for either transmission replacement or new transmission assets. And they're probably going to be fairly pricey. And as I said, if you go across several jurisdictions, I'm not clear in my own mind that the institutional mechanism exists to pull it off.

MR. DAY: I think at least right now, today you're probably correct. Because I used the metaphor that I'm like a new young family that spot their first house. We're house poor. We've spent all our money on these generation resources. I think -- I can't speak for all the utilities -- but everybody's put a lot of money into new construction and --

CHAIRMAN PICKETT: Well, just looking around the room I've counted up about 1.5 billion in the Railbelt.

MR. DAY: And that was, you know, the fish or cut bait question. We had -- we felt like we had to do it. As time goes on and we get a little bit more solid and get some of our debt paid off, we may be able to come up with the money to fund these projects.

But when you have each individual utility looking at a specific project and saying: Gosh, my share of that project is $50 million and for $40 million I could solve that problem with a generation plant, it becomes a financial business decision. And it is very difficult to look at those long-term benefits and justify them against some short-term economics.

CHAIRMAN PICKETT: Right. And I would suggest perhaps that if you only are evaluating it from the perspective of what's going on within your own CPC and geography that you have a duty to serve -- and I'm not discounting economy energy sales or anything like that -- versus a Railbelt-wide look, you'll probably come up with some different conclusions going forward.

MR. DAY: I think you are correct.

CHAIRMAN PICKETT: Anyway, I very much appreciate it. I am hogging the microphone and it's time for me to allow other Commissioners to comment or question.

Commissioner Wilson?

COMMISSIONER WILSON: Just one clarifying question about your numbers. The ML&P numbers, do they include Plant 2A or not?

MR. DAY: They -- yes, they do include the proposed Plant 2A that's under construction right now.

COMMISSIONER WILSON: Okay. Thank you.

CHAIRMAN PICKETT: Commissioner Patch?

COMMISSIONER PATCH: I'll be very brief. Thank you very much, Mr. Chairman.

And, Mr. Salzetti, thank you very much for the opportunity to visit with the FERC Commissioners. I was gratified by the text of Commissioner LaFleur's dissent. And I do certainly hope that you are able to bring to bear your final license application early in December. I encourage you to dedicate effort to that regard.

With respect to the other observation you made, we look forward to seeing you as an applicant for intervention in both the CINGSA rate case and the KBPL rate case.

Mr. Day, thank you for the admonitions. I promise I will leave all the cherry pie I can. I will avoid carrying cats by the tail. But I would point out some work is called for with respect to your barking dog. Silent dogs can sneak up on you and bite.

CHAIRMAN PICKETT: On that happy thought, Commissioner McAlpine, did you want to weigh in on anything?

COMMISSIONER McALPINE: Not at this time.

CHAIRMAN PICKETT: Commissioner --

COMMISSIONER McALPINE: I definitely have thoughts, but I will not weigh in.

CHAIRMAN PICKETT: Commissioner Rokeberg?

COMMISSIONER ROKEBERG: Thank you, Mr. Chairman.

And good morning, gentlemen.

MR. DAY: Good morning.

MR. SALZETTI: Good morning.

COMMISSIONER ROKEBERG: Good to see you, particularly under circumstances where I'm not bound by ex parte rules. I'm going to indulge myself to ask you a few questions. And please indulge me or forgive me for doing so, given this rare opportunity.

CHAIRMAN PICKETT: Before you continue, I am going to allow the AG to chime in if he feels otherwise.

COMMISSIONER ROKEBERG: Very good. I appreciate that, Mr. Chairman.

I particularly was impressed and pleased to see your charts on pages 5 and 8. And I really liked -- the Commission and the various other State agencies worked together when we were working on our initial comments on the so-called clean power plan or 111(d) by trying to account for the total capacity and the effect of EGU's in the Railbelt.

So I'd really love to see your work, if you could provide us with the first level of detail of the particular generating units and how you developed your capacity number, if that's not too much work. I don't want to create a lot of effort, but --

MR. DAY: I believe, actually, the speaker's notes that are attached to the presentation might furnish you some of that information. Because even though the numbers for Golden Valley look a little off or a little small --

COMMISSIONER ROKEBERG: Right.

MR. DAY: -- they have these coal resources. Which a 30-year-old coal plant is not necessarily an old, inefficient plant. They might have upgraded some of the emissions technology, but from an economy standpoint it's still a performer.

COMMISSIONER ROKEBERG: I just wanted to basically proof our work and see what we've done to make sure they're accurate. So this is very beneficial.

MR. DAY: But I'd be glad to furnish any information that I could.

COMMISSIONER ROKEBERG: And particularly one thing we didn't do really is look, as I recollect, at the peaking numbers, which I appreciate very much. And could you tell me if this is what -- how you defined the peaking numbers?

Was this the three CP-type coincident method of peaking, or how did you define the peaking methodology?

MR. DAY: This number that I put in the capacity came off of the federal reporting forms for each individual utility --

COMMISSIONER ROKEBERG: Okay.

MR. DAY: -- and I simply added that number up --

COMMISSIONER ROKEBERG: Okay.

MR. DAY: -- and that's why I was careful to say: This is the non-coincidental peak.

COMMISSIONER ROKEBERG: Okay. This clarifies that. I appreciate that and I look forward to looking into that a little bit further.

Okay. And moving on, if I'm not mistaken, I think Homer has a provision for spinning reserves that are COPA. And you mentioned recent displacement exchanges and so forth to help accommodate that.

Can you explain to the Commission a little bit about how Homer has approached their spinning and ready reserve programs and also the -- what I recollect is an apparent dispute regarding the

Bradley Lake commitments under the Railbelt for spinning reserves and how you resolve that?

MR. DAY: Well, I made a presentation yesterday to the IMC about this difference. And it's a difference of opinion between Homer Electric and the other utilities as to how the obligation for spin should be divided up amongst the players. The IMC has a traditional rule that they've used for a long time, which divides up spin based on your largest unit compared to everyone else's largest unit. And Homer took the position that it should be based on your relative system size. And there's a lot of reasons. We could stretch this out a long time.

But that divide means that under the IMC rules, Homer Electric would have a spin obligation of somewhere in the neighborhood of 22 to 27 MW. And under the load sharing that Homer Electric believes is correct, we would have an obligation of 10 MW. So -- and spin costs money. And we feel that that's a more fair allocation of spin. The other parties don't feel we're right and therein lies the dispute.

COMMISSIONER ROKEBERG: You indicate you'd be able to use some displacement

techniques to accommodate this. It sounds like a real positive provision here.

And are you able to use that both for your ancillary service requirements and obligations to the IMC and also in terms of economy energy sales?

MR. DAY: I think you're mixing up a couple of things here --

COMMISSIONER ROKEBERG: Okay.

MR. DAY: -- that sound like they're all together. Now, when we're isolated from the rest of the system, the spin rules are kind of meaningless because the individual utility, Homer Electric, will do what they think is best for themselves at the time because we're in a contingency situation.

But during that contingency situation we were faced with the aspect of running our very expensive Bernice Lake units, which we would have done to keep the lights on at an economic cost, or we made a deal with ML&P to actually purchase Bradley power -- ML&P Bradley power at Bradley since we're still connected to Bradley. But there wasn't any spin transaction involved in that. It was just simply an economic deal that they offered us power for cheaper than we could self-generate.

Now, normally, we can generate it cheaper than they could offer it to us when our Nikiski unit is available. But it was good for them and it was good for us, so we executed the deal.

COMMISSIONER ROKEBERG: So Nikiski is -- your cogen is cheaper than Bradley Lake?

Is that because of their markup or what?

MR. DAY: This is a problem with pricing Bradley Lake. And I'm glad to see -- Bradley Lake, when you look at the costs -- the actual costs that the utilities pay comes in at about $42 a megawatt hour. Now, that depends on how much water runs into the lake every year. Because the annual costs remain relatively the same. Most generation costs on the Railbelt run in the 60 to $100 range on most of the gas turbines.

Although we have seen transactions when this economic stress comes in that have approached $300 a megawatt hour. So there's this huge variation. Now, what do you charge for Bradley power? Well, you could break even by selling it for $42. That's your cost.

But that means somewhere in the future you've got to run gas generation to replace that power

that you had. And so the real or the pseudo cost of Bradley Lake really reflects your average production cost.

COMMISSIONER ROKEBERG: And speaking of Bradley Lake, could you give us kind of in a nutshell of what's going on down there in terms of repair?

I understood that this year there was going to be some major maintenance going on. There's going to be some spillage. Isn't there opportunities there when you're going to lower the level completely to be able to utilize that water capacity?

And what's been going on? Could you just kind of give us an update on what's happened?

MR. DAY: I'd be real pleased to. We've got three major projects at Bradley Lake that have been bouncing around. The flow of water on the Pelton wheel is governed by six giant needles that are hydraulically operated. And about six months, maybe even longer ago, we developed a hydraulic leak. So we were losing hydraulic oil.

Now, the needles are constructed such that that doesn't enter into the water stream. It

doesn't go into Kachemak Bay. It ends up in a dirty water sump inside the plant. So we capture that. But we've got a leak. We can't control these things. And these weigh about 10,000, 12,000 pounds. This is a big job. But this summer starting July 15th we're going to take one unit out of service, pull all the needles off the wall, bring them up on the deck, rebuild them, put new seals in them, reinstall them, and then operate them.

And then we're going to go to the other unit in October and do the same thing. So for about 30 days we're going to have half the capacity of the plant in July. And about 30 days in October we're going to have half the capacity of the plant.

We're also going to have some -- a lot of transmission work on the transmission line between Anchorage and Fairbanks this summer that's necessary. And whenever we do that, then, of course, the Bradley supply is cut off to the utilities to the north. And that makes it hard for them to use their allocation of water for the year.

And all of this is driven by a big project that is scheduled for next spring in which we have

a bunch of debris that are clogging up what we call the fish water inlets. They deliver fish water to the lower Bradley River to ensure that the salmon have the right amount of water in the lower Bradley River so that they don't get flushed out to the ocean nor do they get dried out because we've starved them from water.

But we can't meet our fish water commitment at all times until we get in there and clear out this rock and debris and mud that's clogging up the inlet, which is on the dam -- on the lake side of the dam. And to do that we have scheduled with all of the utilities to aggressively use Bradley Lake over the next year, even though we have all these outages scheduled, so that come next spring we have Bradley Lake at a very low level and can go in there with mechanical equipment and clear the mud and debris away from the inlet.

So three very big projects. And it's going to take a lot of cooperation. But we tried to make it last year and just couldn't get in there to do the fish water because of storms and other things. But this year we've had very little snow pack. So we're hopeful even with our transmission outages we'll be able to meet those schedules.

COMMISSIONER ROKEBERG: Very good. Very informative. In a general sense you've had testimony this morning that a postage stamp electrical transmission rate would be beneficial. It seems to me that both Golden Valley and Homer are at the opposite ends of our extension cord that we call the Railbelt grid and that a postage stamp rate would be beneficial.

So does that mean that the concept of a USO is more inviting because it may be the only methodology that will be able to impose a singular tariff with a postage stamp rate?

MR. DAY: That's a fun question. But, you're right. Those people who live far from the center love postage stamp because distance usually costs. And it is an impediment to the effective exchange of power to have these various tariffs in place. But the other side of that argument is distance costs. And it costs more if you live far away. And to transport power long distances requires more resources.

So it's two sides of the same coin, which is not an answer. But, yeah, everybody -- whenever you propose something, everybody immediately goes over with their pencil and calculates, what does

this mean to me? And from our calculations, I think Homer would be a beneficiary of that. There are others that made the calculation that said they would pay more than the benefits they received.

So the trick in my mind is to figure out how to levelize that so that when you make that entry that nobody has been fouled and nobody has benefited, but everybody kind of has an equal footing. But that's tough. That's easy to say but very tough to do.

COMMISSIONER ROKEBERG: Thank you for your answer.

One final quick question, Mr. Chairman.

I recently reviewed a June 10th study by the Congressional Research Service about cyber security and it really struck me. And so forgive me for this kind of off-the-wall question, but I have a significant respect for you and your experience here. So I believe you would be an individual I could direct this question to and receive a credible answer.

One of my concerns is -- and I think it's shared by almost all people in the country -- is the nature of cyber security and how we're

prepared to be able to deal with that nationally. But also here in Alaska we have a certain advantage because we're islanded in that regard.

But tell me, is it -- could the Railbelt grid operate if we were to be subject to a major cyber attack and/or, in the alternative, to defend ourselves from that potentiality?

Can we -- can your current system run in a non-digital manner now or could we revert to old-fashioned analog methodology to operate our grid? Are we vulnerable to these types of attack?

MR. DAY: Well, just this last week our IT people had a seminar with us called scared straight. And it is pretty scary what's going on out there. A simple little place like Homer Electric, our corporate network is attacked on the order of 300,000 times a week by various sundry things. Just yesterday my IT guy called me and said: What Web site were you at? You have an infection. And I had no idea what he was talking about. It was some Web site in Alaska that had some malware that was hiding under the Web site.

So even if you're practicing safe surfing, you run the risk of running across somebody that's been compromised. The simple answer for us is

that we make sure that our data systems and our critical infrastructure is not in any way, shape, or form connected to the Internet. It's isolated. That's kind of a policy that worked for the United States in the 1920s, the isolation of this stuff. But we go way out of our way to keep people from using jump drives and compromise it in any way.

But during the fire last week we had some problems with our control system and went to manual. So for three or four days we did run our system in manual. It does cause some uneven operation, some less efficient operation. But I believe here in Alaska for the most part we're capable of running the system manually.

So I think we're surviveable. We take great pains to try and prevent any infection or any problem. We have a lot of tools to search for this malware, viruses. And one of the best things is we just simply don't let our data and control systems associate with anybody else.

COMMISSIONER ROKEBERG: Thank you very much. My suspicions are confirmed. You made a very good answer.

Thank you, Mr. Chairman.

CHAIRMAN PICKETT: And on behalf of

the Commission I'd like to thank you for coming this morning and helping us fill out our record and give a better report to the Legislature. So thank you again for coming.

MR. DAY: Thank you for the opportunity.

CHAIRMAN PICKETT: Agenda item number five is now closed. Agenda item number six is the election of the RCA chairman for FY 2016.

It has been my honor to serve as RCA chairman for FY 2015. For a variety of Commissioner and personal circumstances I'm not able to offer up my name for consideration for '16. But I enthusiastically am nominating Commissioner T. W. Patch. Well, this is going to be a little bit of a railroad job. So Commissioner T. W. Patch to serve as chairman of the Regulatory Commission of Alaska for FY 2016.

Is there a second?

COMMISSIONER McALPINE: I move.

CHAIRMAN PICKETT: Now I'm abusing -- he gave it to me and I'm abusing the point of order. We're going to get the point across and this thing is going to get done.

Are there --

Generation Presentation

RCA Public Meeting
June 24th 2015
Bob Day and Mikel Salzetti
Homer Electric Association

- Alaska Electrical Energy since 1977 (38 Years).
  - Here for Order 19.
  - Construction of the Alaska (A-F) Intertie.
  - Key in the development of the original Data interchange.
  - Present for design and construction of Bradley Lake.
  - Seen most all the interties and interconnections built.
  - Worked for ML&P and HEA.

  - I have lived through most all the attempts to join the Utilities together.

Robert Day, PE

- We have heard a lot of things during this docket.
- I want to emphasize some of the subjects a little more.
- Some important items have been “glossed” over.
- Strongly felt that the Commission may have heard some less than correct information.

- I can talk to you all day about how good fresh from the oven cherry pie with ice cream really is.
- You will know about cherry pie.
- But once you actually have it, you will <u>understand</u> cherry pie.

Why this presentation

- Generation Overbuild?
- Firm Power.
- Utility Cooperation.
- Gas Co-op.

Todays' Cherry Pies

	Capacity	GVEA	Chugach	ML&P	HEA	MEA
Total Installed Capacity	1,910	337	632	549	203	190
2014 System Peak (MW)	852*	202	280	161	79	130
Capacity in excess of 2014 Peak	1,058	135	352	388	124	60
Excess Capacity as % of 2014 Load	180%	40%	56%	71%	61%	32%

Are Generation Resources Overbuilt?

What is of concern to the Generation Planner

- **Efficiencies**
  - The long term effective cost of the resource is important.
  - Both the peak efficiency and the efficiency at low load are important long term.
  - Why is this?
- **Security**
  - The Utility has “A Duty to Serve”.
  - Sufficient power must be “Firm” to meet the load.

- **Contingences**
  - Failure of a system or device must not compromise the "Duty to Serve".
  - A prime example is the recent fire isolating the Kenai.
- **Availability**
  - Some resources may not be available during certain times or even randomly.
    - Wind (intermittent).
    - Solar (daylight only).
    - Tidal (diurnal).
    - Hydro - water limited by inflows or storage capacity.

What is of concern to the Generation Planner (2)

	Capacity	GVEA	Chugach	ML&P	HEA	MEA
Installed Capacity In-Service after 1986	939	157	200	260	133	190
2014 System Peak (MW)	852	202	280	161	79	130
Capacity in excess of 2014 Peak	87	(45)	(80)	99	54	60
Excess Capacity as % of 2014 Load	10%	-23%	-28%	61%	68%	46%

Are Generation Resources Overbuilt?

Exclude resources built before 1986 (30 years old)

- The Utility must have a firm plan in place to supply power.
- Probable contingencies must be planned for in advance.
- The amount of “non-firm” must be limited.

- The Utility has this “Duty to Serve”.
  - To meet load may cause the utility economic stress.

Firm Power

- Lets say Utility A wants to buy 20 MW of Firm power
- Utility B agrees to sell it for $60/MWh.
- If Utility B has a failure and cannot supply, under the ERCOT rules B would purchase from C the necessary 20 MW.
- If C produces for $80/MWh then B loses $20/MWh.

- Guess what?
  - Next time B goes to sell power they don't sell it for the production price they sell it for the "risk" price.

- Economic sales decline. ☹

The Real World

- Utility Load projection is an inexact science.
- Utilities have a duty to serve.
- Utilities must plan for failures.
- Utilities must plan for spinning reserves.
- Utilities must plan for ready reserves.
- Utilities must consider a geographical element in the plan.

- **Peoples lives and well being depend on reliable power.**

What drives the Utilities?

	Capacity	GVEA	Chugach	ML&P	HEA	MEA
Largest Contingency	(80.0)	(63.3)	(60.0)	(60.0)	(80.0)	(17.1)
Installed Capacity In-Service after 1986 (less contingency)	859	93	140	200	53	173
2014 System Peak (MW)	852	202	280	161	79	130
Capacity in excess of 2014 Peak	7	(109)	(140)	39	(26)	43
Excess Capacity as % of 2014 Load	1%	-54%	-50%	24%	-33%	33%

Are Generation Resources Overbuilt?

Not if you consider contingencies!

- Bi-monthly meeting to coordinate maintenance schedules.
- Cooperative activities.
  - Bradley Lake (BPMC, Bradley O&D).
  - Alaska Intertie (IMC, IC).
- Daily communications between Dispatch Centers.
- Frequent discussions over buy/sell excess power/spin.
- Occasional Bilateral short term contracts.
- Economy energy sales (as often as they make sense).

How Do Utilities Cooperate?

“that despite numerous limitations and challenges, the system has been quite reliable. This is a testament to the men and women who actually operate generation and transmission on a day-to-day basis. While utility leadership have disputes about who should pay for what, each day, the lights remain on, and the cost and accounting to make this happen gets sorted out in subsequent months or years.”

From MEA Comments I-15-001

Gas Barriers to Economic Dispatch

- **Energy Sales**
  - Not enough gas (hourly, daily, annual maximums)
    - Storage Cost Adders
    - Swing Gas purchases
    - Peak Gas purchases
    - Inability to serve own load
- **Energy Purchase**
  - Too much gas (monthly or annual minimums)
    - Paying for gas that is not used (Take or Pay Clause / Provision)

- **Buying Utility supplies gas to Selling Utility**
  - Lack of gas transportation agreements
  - Potential for additional gas transportation costs
- **Gas Cooperative**

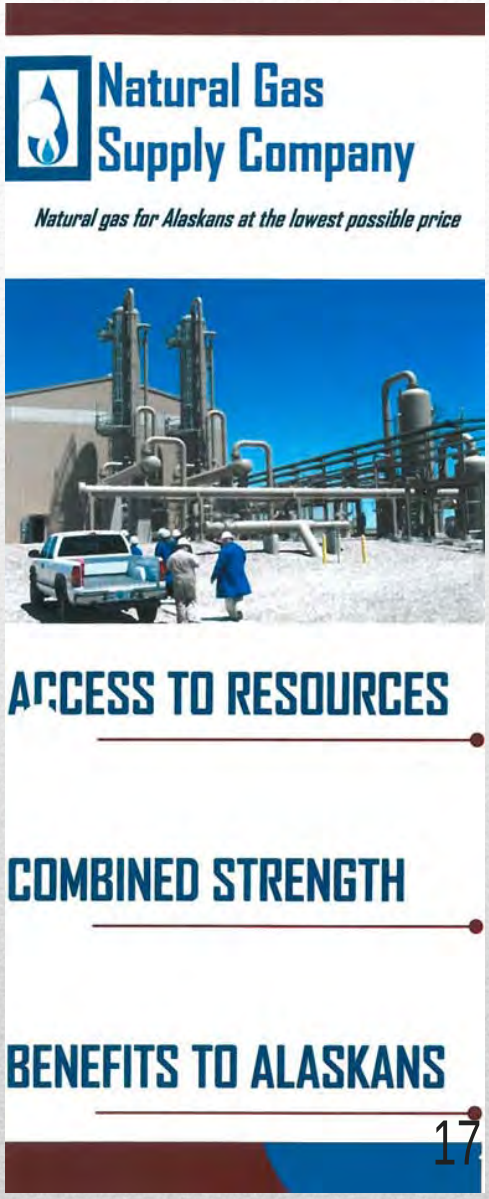
Potential Solutions

Mission:

The mission of Natural Gas Supply Company was to work with natural gas suppliers and Alaska Railbelt electric utilities to develop long-term commitments for purchase and shipment of natural gas and related services.

The thought was by aggregating the natural gas supply needs of several utilities, a larger more reliable and cost effective supply of gas could be achieved.

Natural Gas Supply Company



- **Advantages**
  - Eliminates barriers which facilitates economic dispatch
    - Less gas use by Railbelt Electric Utilities
  - Fuel transportation savings
  - Storage
    - Reduced injection/withdrawal.
    - MEA and GVEA would gain storage rights and share in storage costs
  - Bulk buying power
  - Reduce regulatory expenses
  - Labor Savings
- **Requirements**
  - Railbelt postage stamp transmission wheeling rate
  - Cooperation

Gas Co-op

STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners: Robert M. Pickett, Chairman
Stephen McAlpine
T. W. Patch
Norman Rokeberg
Janis W. Wilson

REGULATORY COMMISSION OF ALASKA
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501

SPECIAL PUBLIC MEETING
June 29, 2015
9:00 a.m.

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P R O C E E D I N G S

CHAIRMAN PICKETT: Good morning, this is a special public meeting of the Regulatory Commission of Alaska. It is Monday, June 29th, 2015, approximately 9:02 a.m. With me on the dais are Commissioners Norman Rokeberg, Commissioner T. W. Patch and Chair elect, Commissioner Stephen McAlpine, and Commissioner Janis Wilson. And I'm Bob Pickett, Chairman of the Commission for two more days.

Agenda item number one is public participation. Would any members of the public care to address the Commission this morning? If so, come to the table, identify yourself for the record, make sure the microphone is on, and keep your comments to no more than five minutes.

MR. McKEE: For the record, my name is Charles McKee. And Tuesday I had delivered this notice of paramount claim upon my private nature divine proportion manifest essence. In other words, I'm claiming all that I am and including up to -- and including my copyright that I have, which you are aware of under TXu -- capital T, capital X, small u -- 45 -- I mean, 545416 under that registration name and number.

address the Commission this morning? Hearing none, we will go back to the east hearing room.

Is there anyone in the Anchorage audience who would care to address the Commission? Hearing none, I will go back to all those online for one last opportunity.

Does anyone care to address the Commission this morning? With that, agenda item number one is closed.

Agenda item number two, I-15-001, in the matter of the evaluation of the operation and regulation of the Alaska Railbelt electric transmission system. In starting, I would first like to thank all of you who have been involved with this process, the public portion which began actually in late January but, frankly, over the course of the last year as we developed our findings and recommendations.

This is a very challenging set of issues we are dealing with. They are not easy issues. But I think it is fair to say and I think it will be the decision of the Commission that the status quo is not acceptable. The way I'm going to approach it this morning -- and the Commissioners have all been provided with a five-page document that I'm

going to use as the basis for ten separate motions that will cover findings and recommendations. Further comment -- and this is perhaps reflecting more my own personal beliefs than those of the Commission at this point, though I've had sidebar conversations with them.

The purpose of our recommendation is not to identify a specific number either for anticipated transmission, let alone specific transmission projects that may be needed at some point in the future, let alone the anticipated savings associated with such activities. And the same is true with the issues surrounding economic dispatch.

We have run so many scenarios and sensitivities based on a wide range of assumptions. I, quite frankly, think it's disingenuous to the public to put specific numbers out there and hold that this is going to be the number. Because, quite frankly, the range is somewhere between 20, 25 million to 300 million based on your assumptions, and that's a pretty big range. But I think it is fair to say there are benefits. And, at the end of the day, benefits that in my mind will flow to ratepayers that make

movement forward necessary and important.

With that, I'm going to start and the motions I make will have the language that I provided the Commissioners, though there will be some additional wordsmithing because the last three or four days have been a crunch. And you know how it is with wordsmithing and that kind of stuff. But I'm going to read it into the record, and fortunately I have four other Commissioners here to correct -- but there's certain things -- and I talked to Commissioner Patch this morning on some things he's picked up, and we will be incorporating those types of changes into it.

So my first motion is this and it concerns finding number one. I am moving this finding: The present Railbelt electric transmission system requires institutional reform. The balkanized ownership of transmission assets and legacy power purchase agreements constrain and limit the effective and efficient operation of the Railbelt grid. The Commission believes that no significant State funding will be available for Railbelt transmission replacement and upgrades. No institutional structure currently exists that is capable of providing significant capital for

transmission projects across service areas of several Railbelt utilities.

Do the Commissioners understand the motion? Is there a second for purposes --

COMMISSIONER PATCH: There is a second.

CHAIRMAN PICKETT: Commissioner discussion on the motion before us? Seeing none, we'll move on to the vote.

All those in favor of the motion say aye.

(Collective aye.)

CHAIRMAN PICKETT: Let the record reflect the motion passes unanimously.

The recommendation associated with finding number one. I move the following: An independent transmission company should be created to operate the transmission system reliably and transparently and plan and execute major maintenance, upgrades, and major new projects. This independent transmission company should be certificated and regulated as a public utility under AS 42.05. The Regulatory Commission of Alaska should be granted siting authority for new generation and transmission and granted explicit authority to regulate integrated resource planning in the

Railbelt electrical system.

A mandatory report on the status of the current efforts to develop an independent Railbelt electric transmission company shall be filed with the Commission no later than September 30th, 2015. A second report on transmission restructuring shall be filed with the Commission no later than December 31st, 2015.

Failure to file these reports will be construed as a failure of the current voluntary efforts to develop an independent Railbelt electric transmission company. If voluntary efforts fail, the Commission will work with the Legislature and the administration to develop and implement specific action steps to create an independent Railbelt electric transmission company.

Is there a second for purposes of discussion?

COMMISSIONER PATCH: There is a second.

CHAIRMAN PICKETT: Commission discussion?

Commissioner McAlpine?

COMMISSIONER McALPINE: I think, Mr. Chairman, for the benefit of the audience that

we ought -- I'm sure it is clear to most, but I want to be perfectly clear for the record. What we're looking to first is a voluntary effort upon the part of the existing utilities to put this together. And that if that voluntary effort fails, then it's the Commission's belief that there ought to be a mandatory injunction brought about to form this independent organization to take over.

So I guess with the abundance of caution, the red flag has gone up that this is really the last chance to put together a cooperative effort before some mandatory relief is imposed.

CHAIRMAN PICKETT: Thank you for that clarification, Commissioner McAlpine.

Commissioner Rokeberg?

COMMISSIONER ROKEBERG: Thank you, Chairman. And just a query of the maker of the motion as to the issue regarding explicit authority to regulate integrated resource planning.

Is there some thoughts given to the funding sources or how this could be structured?

CHAIRMAN PICKETT: We will get into the resource impacts on the RCC as we get to

finding and recommendation number five.

COMMISSIONER ROKEBERG: Okay.

CHAIRMAN PICKETT: Further discussion on the motion concerning recommendation number one? Seeing none, we'll move on to the vote.

All those in favor of the motion say aye.

(Collective aye.)

CHAIRMAN PICKETT: Opposed? Let the record reflect the motion passes unanimously.

Finding number two. I will make the following motion: Although short-term bilateral economy energy transactions occur in the Railbelt electric market, true economic dispatch of generation units on a system-wide basis does not occur. The Railbelt electric system does not deliver maximum benefit possible to the ratepayers who are paying and will be paying for 1.5 billion in new generation.

The various independent system operators or ISO's existing in the Lower 48 are appropriate in very large, fully restructured, unbundled markets. This ISO model in the Railbelt electrical system is an overly complex institution for a limited number of generation units and relatively small

loads. Other models may be more appropriate for the Railbelt grid. Nondiscriminatory access to the grid, open and transparent system-wide transmission pricing, and economic dispatch at generation by an independent entity are key principles that must guide the transformation of the Railbelt electric system.

Is there a second to the motion?

COMMISSIONER McALPINE: Second.

CHAIRMAN PICKETT: It has been moved and seconded to finding number two. Is there Commissioner discussion at this point?

I will just make a few comments on this. This is a very, very challenging area. And as you see when we get into our recommendation, much work needs to be done. But I think the principles of economic dispatch are so important that, again, the status quo is not acceptable.

With no further Commissioner discussion we will move on to the vote on finding number two. All those in favor of this finding say aye.

(Collective aye.)

CHAIRMAN PICKETT: Opposed?

The recommendation associated with finding number two: System-wide merit order economic

dispatch of the Railbelt's electrical generation units will bring maximum benefit to the ratepayers. The Commission should use all of the regulatory and statutory authority it currently has to strongly promote economic dispatch and seek new statutory authority as needed to promote this goal.

Voluntary efforts by utilities to use loose power pools should be encouraged as an interim step towards a tighter power pooling system. As actual data is generated concerning costs, benefits, and other outcomes of voluntary pooling strategies, quarterly reports shall be filed with the Commission. These reports will be analyzed and reviewed to assess the organizational and governance structure needed for an independent consolidated system operator.

The first report shall be for the fourth quarter of 2015, October 1, 2015 through December 31st, 2015, and shall be filed no later than January 30th of 2016. Quarterly reports shall be filed with the Commission through 2016 due no later than 30 days after the end of the applicable reporting quarter.

Failure to file these quarterly reports will

be construed to reflect a failure of voluntary efforts to move toward system-wide merit order economic dispatch. If voluntary efforts fail, the Commission will work with the Legislature and the administration to develop and implement specific action steps to institutionalize system-wide merit order dispatch.

Is there a second to the motion?

COMMISSIONER McALPINE: Second.

CHAIRMAN PICKETT: Commissioner discussion?

I will note this recommendation does not endorse at this point in time any specific institutional structure. I think there's a number of different models that remain on the table, and I don't think it would be appropriate for the Commission to recommend a highly bureaucratized, costly institutional structure if that is, in fact, not needed.

And so we're trying to give the voluntary efforts an appropriate time frame to work, assess the results and the outcomes from those efforts, and then work with the appropriate parties if that's not sufficient.

We'll move on to the vote on recommendation

number two. All those in favor of the recommendation say aye.

(Collective aye.)

CHAIRMAN PICKETT: Opposed? Let the record reflect the recommendation passes unanimously.

Finding number three. I make the following motion for a finding: The past efforts to reform and rationalize the Railbelt electrical system have failed. Much time and money has been expended on consulting reports, endless meetings, legislative hearings, and many frustrating hours in RCA's east hearing room. A great deal of skepticism exists about the ability of the electric utilities to voluntarily reform and restructure the Railbelt grid and move towards true merit order economic dispatch.

Non-utility independent power producers and larger institutional customers have complained about the current structure and insist that a level playing field is needed. The lack of trust and relying upon free money for transmission from Juneau has contributed to this dysfunctional history.

Is there a second for this finding?

COMMISSIONER McALPINE: Second.

CHAIRMAN PICKETT: Commissioner discussion?

These are --

COMMISSIONER ROKEBERG: Mr. Chairman?

CHAIRMAN PICKETT: Commissioner Rokeberg?

COMMISSIONER ROKEBERG: You talked about wordsmithing. In the last sentence about free money for transmission from Juneau --

CHAIRMAN PICKETT: We'll work it out. I'll talk to you, Commissioner Rokeberg.

COMMISSIONER ROKEBERG: Okay.

CHAIRMAN PICKETT: I think the point of this is, in a strange sort of way even when the State was flush in money and the competition for this money -- I mean, there were efforts to sort of rationalize it and consolidate it, but I think history does show that it created some rather interesting dynamics.

Further Commissioner discussion on finding number three? Seeing none, we will move on to the vote.

All those in favor say aye.

(Collective aye.)

CHAIRMAN PICKETT: Opposed? Let the record reflect that finding number three has passed unanimously.

The recommendation associated with finding number three. I move the following: Though past history strongly indicates that the current voluntary transmission restructuring and economic dispatch efforts by the utilities may fail, the Commission believes they must be given the opportunity to succeed. The time lines outlined in recommendations one and two allow for this potential success. Failure of the voluntary efforts and initiatives will trigger the compulsory steps identified in recommendations number one and two.

Is there a second to the motion?

COMMISSIONER McALPINE: Second.

CHAIRMAN PICKETT: Commissioner discussion? Seeing none, we'll move on to the vote.

All those in favor of recommendation number three say aye.

(Collective aye.)

CHAIRMAN PICKETT: Opposed? Let

the record reflect the recommendation passes unanimously.

Finding number four. I move the following: Reliability standards for the Railbelt electric grid are voluntary and not all electric utilities have adopted the same standards. The Intertie Management Committee, IMC, formally adopted the Railbelt Operating and Reliability Standards at its meeting on November 1st, 2013. The IMC includes the Alaska Energy Authority and the participating utilities: Chugach Electric Association, Golden Valley Electric Association, Matanuska Electric Association, and the Municipality of Anchorage doing business as Municipal Light & Power. The IMC reliability standards were filed with the Regulatory Commission of Alaska on January 27th, 2014.

On December 9th, 2014 Homer Electric Association for itself and on behalf of the Alaska Electric and Energy Cooperative filed with the RCA the Reliability Standards of the Railbelt Reliability Committee as modified and adopted by Homer Electric Association.

Is there a second for this finding?

COMMISSIONER McALPINE: Second.

CHAIRMAN PICKETT: Commissioner discussion? Seeing none, we'll move on to the vote.

All those in favor of the finding say aye.

(Collective aye.)

CHAIRMAN PICKETT: Opposed? Let the record reflect that finding number four is adopted.

Recommendation number four. I move the following: Enforceable and consistent Railbelt operating and reliability standards are necessary. The Regulatory Commission of Alaska will strongly encourage the IMC and Homer Electric to resolve their differences and develop a common Railbelt operating and reliability standard. In January 2016 the RCA will initiate a process to determine if it should adopt regulations concerning Railbelt operating and reliability standards.

Is there a second for this recommendation?

COMMISSIONER PATCH: Second.

CHAIRMAN PICKETT: Commissioner discussion?

Commissioner Rokeberg?

COMMISSIONER ROKEBERG: My only

concern here is looking at it from the standpoint of whether sufficient authority on the part of the Commission to act in a regulatory sense, given other agencies' responsibilities -- if there is any conflict with laws and/or responsibilities, it may need to be worked -- may need to be more legislatively founded in terms of our regulatory authority.

CHAIRMAN PICKETT: The wording is specific to say we will initiate. We are not committing to a rulemaking process at this point. In the scoping process, the initiation process, all of those including the comments filed in this docket I think will come out. And we will be working with the appropriate parties, the administration, and the Legislature in that scoping process.

Further Commissioner discussion or comments? Seeing none, we'll move on to the vote for recommendation number four.

All those in favor of the recommendation say aye.

(Collective aye.)

CHAIRMAN PICKETT: Opposed? Let the record reflect that recommendation number four

has passed unanimously.

Finding number five. I move the following: The RCA recommendations above will be challenging and time-consuming. Full implementation of the proposed Railbelt electrical system structural changes will likely take five to ten years. Many obstacles remain to be overcome. The time-critical recommendations identified above are a start, but many additional concrete building blocks must be identified in the months ahead. Many different parties must cooperate or this effort will fail.

The Legislature, the administration, Railbelt utilities, independent power producers, the RCA, RAPA, and most of all the ratepayers have much at stake. RCA resources will be stretched and stressed as the structural reform of the Railbelt energy electrical system progresses.

Is there a second to the motion?

COMMISSIONER PATCH: I enthusiastically second the recommendation -- excuse me -- the finding.

CHAIRMAN PICKETT: As I fully expect the future RCA chairman to do.

Is there further discussion on the motion

that's seconded? We'll move on to the vote -- did you have a comment, Commissioner Wilson, or are you just reaching to vote?

We'll move on to the vote. All those in favor of the motion before us signify by saying aye.

(Collective aye.)

CHAIRMAN PICKETT: Opposed?

Finding number five passes unanimously.

The recommendation associated with finding number five. I move the following: The Regulatory Commission of Alaska will be hugely impacted by these proposed Railbelt electrical system changes. The initial action steps will need to be implemented within existing RCA resources. The Commission is self-supporting to regulatory cost charges and doesn't rely upon State general funds. If the RCA receives the necessary administration and legislative support, the FY 2017 RCA budget will reflect the necessary RCC-funded resources to implement these proposed recommendations.

Is there a second to the motion?

COMMISSIONER PATCH: There is a second.

CHAIRMAN PICKETT: Commissioner discussion? Seeing none, we'll move on to the vote.

All those in favor of the motion say aye.

(Collective aye.)

CHAIRMAN PICKETT: Opposed? Let the record reflect the motion passes unanimously.

These findings and recommendations will be incorporated into our letter to the leadership of the Senate and the House of the Alaska Legislature that will go out tomorrow with an associated several-thousand-page pdf of this record.

We will be working through the balance of July and early August with the Legislature on helping them understand the findings, recommendations, and getting the full record in a format that will be a little bit more user-friendly for the Legislature, their staffing, and the public, and the utilities, and all those who have participated in this effort.

Again, I want to thank all of you. I will single out Dr. Scott who we've worked with for the past year. Thank you very much for your efforts. And Bernie Smith who will be with the Commission for another couple of days. But, Bernie, your

efforts have been invaluable. David Lawrence, and Anne Marie, and Ann Wilde on the RCA staff. It's truly been a team effort. And to all my fellow Commissioners for the time, effort, and commitment that they have put into this effort.

In closing, any Commissioner thoughts? Observations? With that -- oh, Commissioner Patch?

COMMISSIONER PATCH: Thank you, Mr. Chairman. I second as well as I did some of the findings and recommendations, your observation of our staff who has done yeoman work. It is truly an indication that no matter how strong a star you have leading the effort, that it remains a team game to produce a product that is this voluminous and distills to these types of findings and recommendations.

I think it likewise appropriate to acknowledge that the utility companies themselves are dissipated knowing full well what had to be done and that their involvement and indeed their commitment would be necessary to benefit their customers, our ratepayers, and our legislative voters, and, if you will, taxpayers.

I think this in time may prove to be a most

noteful and I hope singular benchmark for the Commission's process, for its staff and how they go about doing the business they're assigned to do. I commend you on your calling out the regulatory affairs and public advocacy section as critical to the work we do.

I hope that what will be seen once this report is public is, if not universal acclaim for specific findings, at least universal recognition for the quality of effort in the road map you've laid out for us. And I thank you especially for your foresight and your leadership. This was not an easy charge to respond to. And I am very satisfied that we have done well.

Dr. Scott, I did not mean to ignore you any more than I meant to ignore Mr. Peterson who was brought forward by Chugach or the work of any other employee of any utility or the work of AEA.

That concludes my remarks and I thank you all.

CHAIRMAN PICKETT: Commissioner Rokeberg?

COMMISSIONER ROKEBERG: Thank you, Mr. Chairman. I, too, wish to commend you for providing leadership as well as everybody that's

participated in this. This was very much a team effort and with broad participation from the public and the affected utilities. I'm very pleased about that.

I've personally devoted a portion of my life for the last two decades to this issue and taken some interest in it. But I think for the first time I see an opportunity and a reflection point, if you will, that's going to develop some meaningful action. It is not another doorstopping study. And I think that we are at the threshold of making a truly transformational change in the restructuring of the Alaska Railbelt energy grid. I'm very pleased to see that. I'm looking forward to participating in this process.

And thank you, again, Mr. Chairman.

CHAIRMAN PICKETT: If there are no additional Commissioner comments, that will close out agenda item number two.

Agenda item number three, other business. I've asked Commissioner Patch to handle a piece of business that's sort of unusual that we do this from the dais, but --

COMMISSIONER PATCH: Thank you very much, Mr. Chairman. If I might request a recess

in place, I did hear just a short while ago that we are having some technical difficulties.

Mr. Smith, could I ask you to try and find one of our IT persons. If Mr. Luckey is not available, maybe then perhaps Mr. Wike would be acceptable.

CHAIRMAN PICKETT: We'll take a brief at ease.

COMMISSIONER PATCH: To those in attendance, thank you very much for the indulgence while we try and garner some technical assistance so we can reduce the static and other things. I'm not intending to meaninglessly prolong your morning. We do appreciate your attendance, all of you, both those on the telephone as well as those in attendance at our east hearing room. But so that the record can remain clear so that the court reporter can do her job, I insist on trying to get this done correctly.

And since that's my insistence and I have limited powers, Mr. Wike and Mr. Smith, I ask you to please come forward.

It is truly a delight to call you friends, each of you, and to call you valued members of the RCA team. It is with esteem and gratitude that we

would like to confer upon each of you -- we Commissioners would like to confer upon each of you a certificate of appreciation and a declaration that the public's convenience and necessity for utility service has been well served by each of you.

Bernie, as you are aware, you've very capably served not only in this most recent proceeding docket but as utility engineering analyst, and once upon a time you were a very valued member who sat at this dais. And in preparing your certificate I can tell you that I learned your first name is Roy. And so if that embarrasses you -- and I hope it does -- then I nonetheless beg your indulgence for embarrassment and I deliver to you a certificate representing the Commissioners' thanks.

David works in the background. You probably don't see him very often, but we see him quite frequently. And he was the reason we had a little technical glitch, because he wasn't going to show up unless I arranged it. So if you see him nod his head and smile, you know I did the right thing by summoning him in that somewhat disingenuous fashion.

David, your certificate of appreciation was fun to craft. And after the declaration that the public has been well served, there is some additional language. That you are wondrous in your ability to accomplish technological wizardry on all systems phone and computer. That you're highly valued and we do confer upon you by this certificate the title of Chief IT Imperial Wizard. Thank you very, very much.

I wish -- we all wish you and Bernie both the very best of your endeavors in life and employment long after your departure from this Commission. And you will both be fondly and deeply remembered. And for your service, deeply appreciated.

MR. WIKE: Thank you. It's been great.

COMMISSIONER PATCH: I have no other business -- no further other business at this time, Mr. Chairman.

CHAIRMAN PICKETT: Do any of the other Commissioners have any other business?

Commissioner Rokeberg?

COMMISSIONER ROKEBERG: I'm just hoping that the certificates do not entail the requirement of payment of RCC's.

CHAIRMAN PICKETT: I tried to get that in the fine print and reporting requirements, but T. W. balked at it.

COMMISSIONER PATCH: Duly noted.

CHAIRMAN PICKETT: If there is no other business to come before the Commission this morning, agenda item number three is closed.

I spoke with the attorney general this morning and there is no need for an executive session. So agenda item number four is closed.

Is there a motion to adjourn at 9:40 a.m.?

COMMISSIONER PATCH: So moved.

CHAIRMAN PICKETT: Second?

COMMISSIONER McALPINE: Second.

CHAIRMAN PICKETT: All those in favor of adjourning at 9:40 a.m. signify by saying aye.

(Collective aye.)

CHAIRMAN PICKETT: Again, thank you all for being here this morning and your participation in this docket.

(Adjourned - 9:40 a.m.)

TRANSCRIBER'S CERTIFICATE

I, Adrianell Poteet Sorrels, hereby certify that the foregoing pages numbered 1 through 31 are a true, accurate, and complete transcript of the Public Meeting of the Regulatory Commission of Alaska, held on June 29, 2015, transcribed by me from a copy of the electronic sound recording to the best of my knowledge and ability.

_____ _____

Date Adrianell Poteet Sorrels, Transcriber