TRANSMISSION, INTERCONNECTION, AND INTEGRATION ISSUES WEBINAR

May 19, 2010

Coordinator: Welcome and thank you for standing by. All participants will be in a listen only mode for today's conference. Today's conference is being recorded. If you have any objections, you may disconnect at this time.

I would now like to turn the call over to Mr. Garrett Shields. Sir, you may begin.

Garrett Shields: Good morning or afternoon as the case may be. My name is Garrett Shields from BCS Incorporated. And I would like to welcome all of you to the third in a series of Webinars in 2010 sponsored by the NRECA, APPA, WAPA, DOE Wind and Hydropower Technologies Program, NREL, UWIG, (ALIA) and the NWCC.

The subject of today's Webinar is Transmission, Interconnection and Integration Issues. This Webinar will address the interconnection, engineering and operating issues that need to be considered when interconnecting wind turbines to distribution systems. Lessons learned in post installation operating experiences will be presented based on actual case studies, the results of Nebraska Power Association Wind Integration Study will also be discussed. And then updated - or an update on storage technologies and their role in grid support and renewable resource integration will be provided.

I will be the moderator for today's session. And we have a distinguished panel of speakers today that includes Tom Wind from Wind Utility Consulting, Clint Johannes from Nebraska Electric Transmission Cooperative and Paul Denholm from NRECA.

I will encourage you to submit questions electronically at any time during the Webinar. And we will try to address as many of them as we can at the conclusion of all the speaker presentations. But since Tom Wind has to leave early due to a prior commitment, I will try to address questions for Tom at the conclusion of his presentation.

We are currently working on posting answers to questions that we are not able to get to on the Web - on the repartners.org Web Site. The repartners.org Web site will also allow you to go back and replay the audio recording and view the presentations from this and all the previous Webinars in the current series.

Finally I'd like to let you know that the next Webinar in the series will be held on September 15, 2010. And the tune of topic will be Partnering to Achieve Economies of Scale for Consumer-Owned and/or Community Wind Projects. So be sure to visit the repartners.org Web site for future updates and registration information.

I also want to mention the views and positions expressed by today's features do not necessarily reflect the views and positions of the individual sponsors of this Webinar series. And we hope that today's presentations will generate a constructive dialogue focused on the challenges of interconnecting and integrating wind projects in a consumer-owned utility energy supply portfolio.

And with that I'd like to introduce Tom Wind from Wind Utility Consulting. Mr. Wind is the owner of Wind Utility Consulting. Mr. Wind specializes in small wind generation projects and in the integration of large wind turbines into the utility grid systems. He graduated from Iowa State University in 1974 with a B.S. in Electrical Engineering. He was employed at Iowa Southern Utilities for 15 years before becoming a self-employed consulting electrical engineer.

He's a member of the American Wind Energy Association, the Utility Wind Integration Group, the Institute of Electrical and Electronic Engineers, the U.S. Technical Advisory Group for Wind Generation for the IEC, the Mid-Continent Area Power Pool Transmission Design Review Subcommittee and is an Iowa Power Fund Board Member. He has given over 100 technical presentations at meetings and seminars over his career. Tom?

Tom Wind: Yes. Garrett, thank you for that introduction. I'm going to talk about integrating or connecting large wind turbines to the distribution grid. Okay, let's see if this transition works okay. The topics I'll talk about today include: The key technical and operational issues for distributed wind interconnections; what are the electrical and power quality impacts of wind turbines; examples of distributed wind generation interconnections and key issues involved with those.

The key technical issues. Well the first one is power quality when connecting to the distribution system. And that includes voltage levels during operation; voltage flicker during turbine start-up and if you have a two-speed generator during - switching from one generator to the other; and then the last one is operation of the substation and line voltage regulators and any potential interactions between those.

Voltage levels during operation. Voltage levels can rise at the point of interconnection and it's most pronounced during full generation during light load periods. And for distribution connected wind turbines the voltage levels can exceed design standards out near the wind turbine point of interconnection, especially if the bus voltage levels are already at the maximum level that you would normally operate at.

So you need to look at what the voltage levels will be at light load conditions and high wind and then of course at heavy load too. And I have found many times that this voltage level requirement often will dictate where you can and can't put turbines on your distribution system.

Okay. Here is a map of a - actually a wind speed map around Algona, Iowa. And you can see the highest wind speed is down there in the orange area. And in 1998 we installed three wind turbines at that site. And what is unique about this was that that site is about six miles away - six and a half miles from the substation. The substation is at the east edge of the city there. It's an MVA substation.

But the line that went out to the country served rural customers and by the municipal utility. And it was only 1 (ah) ACSR wire and what we installed is three 750 kilowatt turbines or 2250 kilowatts. I don't think any utility had ever installed that much generation that far out on a distribution feeder in the United States.

So this was a test of can we install that much wind generation out there and would there be technical problems with doing that. Here's a one line diagram of that installation. It shows the 10 MVA transformer on the left and it's connected to a three-base circuit and the six miles of line resulted in quite a lot of voltage drop or voltage rise along that line. And as you generate power out of the end of a six-mile line the voltage level would go up quite a lot. And as a result we had to operate these turbines at 92% lighting power factor. In other words the turbines would generate power which would go back to the substation, but they would absorb reactive power or VARs and the absorption of that power kept that voltage level at a manageable level.

The option normally you would not run wind turbines like this in that kind of a (liking) power factor. But the option was to rebuild that line to 4(ah) wire and which would have cost quite a little bit of money. And an economic analysis said that it was more cost effective to simply run that at 92% (liking) power factor. Now we increased the distribution losses on this. But again, it was an economic choice to do that.

So these turbines have the ability -- in fact we specified that as part of the contract for these turbines that we wanted to be able to set the power factor and run it at off unity power factor. Fortunately everything worked as planned and they operate to this day.

We changed the power factor from summer to winter. In the winter we operate at 92%. In the summer we operate at 90% power factor. And the difference is is because the resistance of the wire is higher in the summer and it's lower in the winter and that makes the difference in why we have to operate that.

As you know the wind speed varies all the time. The top is a graph just showing the wind speed variation of I believe over a 24-hour period here. And the middle graph is the power output from these wind turbines over that same period of time. You can see the power output. Often times it goes from zero to full load during the day. And when the power output changes so does the distribution line voltage -- and that's the bottom graph. And variations in the distribution line voltage normally don't cause a problem as long as they don't happen too quickly or are observable by the customers on the line.

But changes in the voltage level -- especially if they're quick -- will cause voltage flicker. And during generator startups or generator switching there is an in rush of current into the generator or magnetizing the generator and the core. And the in rush of current, you know, will drop the voltage a little bit.

And whether that drop in voltage is noticeable by the customers, it will depend upon the magnitude of that voltage drop and how often it occurs. Magnitude of the flicker or the voltage drop depends upon how stiff or how robust the line is and the voltage level. Also and how robust the line is or its capability depends upon the distance from the substation, the size of the substation transformer and the wind turbine electrical design.

So there are several factors that go in to determining, you know, what the amount of voltage flicker you will have from a wind turbine. And all four of those factors need to be considered when you look at to see whether you're going to have a problem with voltage flicker or not. And we determine that by looking at either the curves from IEEE or we use the International Electric Technical Commission standards for voltage flicker. And I'll get into that in just a second.

Here's a graph for a - I believe this is a 750 kilowatt - or excuse me, a 900 kilowatt wind turbine. It's no longer made, but there are many of these out in the United States. And it shows at 90 seconds there when the wind turbine starts up. And the red line is the current. And the green line is the voltage at that particular point. But the red line shows that as soon as like at 86 seconds when the turbine starts up there is a current surge equal to 55% of its nameplate rating. And then that current surge settles down to about 25% and then I believe capacitors come on line after that and a couple two or three steps and then the current goes on down to a very low level which is the amount of power that the turbine's putting out at that point.

The point is is that initial surge is - but could potentially cause the voltage to dip enough that customers would see it. To determine whether a change in voltage is going to cause a problem we refer to either the older IEEE curves or the newer IEC curve, which is shown at the top. And the two bottom curves just show as the amount of voltage change versus how often you can have it before you will - it'll be either seen or the middle curve is where it becomes a point of irritation to customers.

For example if you look at a 3% voltage dip on the left and you look at the middle curve, you'll see that you can have a 3% voltage dip about ten times per hour and is about the maximum you can have. And anything above that then customers will start calling you. Well at least one customer, probably the most sensitive customer will call you and complain. "Say, I think something's wrong with my power here.

I see these flickers." So the goal is - and you design an installation like this is always to be below the borderline of irritation by some margin. And if you're below the bottom curve, then well nobody will even see it, will even notice it. Now the IEC curve -- the top curve -- is a more modern curve and it's more applicable to wind turbines. And that's the curve that I typically use for evaluations.

Here's an example of a voltage flicker issue that we had in Southern Minnesota. In 2003 two 950 kilowatt wind turbines were installed. And you can see those in the picture. And that power pole in the foreground is the interconnection point. It is simply connected up through three disconnect fuses there; that is the total interconnection. The metering is over on the right side of the right turbine there in a little pad mounted cabinet there. So it's a very simple installation. But we were concerned that these particular turbines have a high flicker characteristic to them. And we were a little bit concerned. We thought we were on the edge of what could possibly cause problems with nearby neighbors. But utility in this case decided to move ahead and thought that would probably not cause any problems.

And so we put the turbines up and we looked at the voltage levels and the flickers. And it turned out that the calculations made according to the standard procedures are very conservative and that there were no complaints from flicker at this installation or from the nearby neighbors on that power line. In fact there was enough margin that the utility was able to add two larger wind turbines right adjacent to - across the road connected very close to this. And these larger turbines actually had a lower flicker characteristic because of their design. And with the addition of those two turbines -- so we had four turbines on that line -- we still didn't have any flicker - voltage flicker issues.

So again you need to check voltage flicker and to see if it is an issue. Here's just a little topographical map showing where those turbines are. The turbines on the left were the first two that were installed and then the two additional turbines -- 1650 kilowatt turbines -- were installed a year later. The ones on the left have I believe a two-speed generator in them.

And it was during the switching from one generator to the next that caused a lot of - caused us the most concern. But the two larger generators only had a single speed generator. So as a result it didn't have as many transients because it just switched on typically once or twice a day.

So this graph actually shows the amount of flicker that we've calculated with all four wind turbines as having what we call a Flicker Severity Index, a short term of .739. A Flicker Severity Index of 1.0 is the point where you would expect that customers -- at least the more sensitive customers -- would call to complain. So typically I like to be around a maximum of .8 or so. In this case we were, you know, fairly near that. And again no complaints from any of the customers. So this is a successful installation. I think maybe we're pushing the limit a little bit, but it turned out that it was just fine.

Here's another case where par quality issues were very important. One is the small town of Lenox, Iowa, about 1500 people in Southern Iowa. They installed a 750 kilowatt wind turbine there, but they had a very weak grid. It was a 4.16 kV grid there. And we built a two-mile long dedicated feeder out to this wind turbine which was on the edge of town. And we connected that - we didn't connect that feeder to the closest point on the distribution system. We instead built back closer to the substation so as to limit the impedance of the feeder.

And it turned out that they actually wanted to install a larger turbine there, but I was a little bit afraid of that; that we could get into voltage problems. So we went with the smaller 750 kilowatt wind turbine. And it appeared that we might be into have problems there, but we didn't have any problem after all.

Another installation, another small town putting a 660 kilowatt wind turbine in. They only had a 2.4 kV grid; that's the lowest voltage grid that I've ever heard of a wind turbine being connected to at the time that we did this project. And we had the cables - took the cables -- underground cables -- and went directly back to the substation. In fact we bypassed the voltage regulators because of their impedance and connected right to the low side of the 69 to 2.4 kV transformer. Again calculations show that it would be okay. And sure enough it was; never heard any complaints about any voltage flicker when the turbine starts up.

Here is a case of a turbine installed I think in 2002. I was not involved in this project by-the-way. It had problems. They installed a 900 kilowatt wind turbine and they put it on a very small substation that had a three-quarter mile underground cable.

And they had 9% voltage dip on turbine startup. And as you might guess the additional customers that were served off of this same 12.47 kV system complained. And as a result they had to come back and put a dedicated circuit in. This utility that installed this hadn't even considered flicker, hadn't done any calculations and just thought you could hook a turbine up anywhere you wanted to. Well they soon learned that you could not do that.

I've done several evaluations over the years. And I'd like to show you an evaluation of a rural electric system where we looked at - well we asked the question, how many large wind turbines could you install on the existing distribution system of the Highline Electric Association of Colorado? We took their electric system data, which is shown here; this is their - most of their service territory.

And the red lines represent three-phase 12.47 kV lines. The green lines represent single phase lines. And in this area there's a lot of irrigation. So we have 50 horsepower to 100 horsepower irrigation motors. This system is well-designed. It's a robust system. It's got 69 and I believe 115 kV lines. The blue lines are the transmission lines there -- excuse me. Yeah, transmission lines either 69 or higher. And the substations are typically 10 MVA. The peak load in the system is about 150 megawatts.

So the question was asked, could we use this system for collecting wind power and then putting that wind power back up on the higher voltage blue lines? And how many wind turbines could we put on this system? Because at the time we did this study there was some concern about the people or the landowners in this area losing their water rights because of a legal issue between the state of Kansas and Nebraska. So the utility served about 150 megawatts of peak load, but their average load was more like 10 or 20 megawatts typically without irrigation.

So they had this wonderful robust distribution system that was designed for irrigation. But if they were going to lose all that load, they were wondering what are we going to do with all these assets? What could we do with it? So one question is well could we turn the power flow direction around and use it for collecting wind power? So I was hired to do this evaluation. And we again considered the local electric cooperative's design criteria for voltage drop and flicker. And we used that information.

We plotted out what the wind speed was in the area. And especially we focused on each of the substations because we knew from previous studies that large wind turbines can only be installed typically three or four miles away from the substation -- five perhaps at most.

And so the wind turbines would be scattered around the substation, you know, near three-phase lines. So in the middle of this diagram is the substation. And then we've got the four feeders - five feeders out are color coded: Red, white, purple, blue and black. And those little white circles represent 1500 kilowatt turbines. And I use the General Electric turbine.

And in this particular case we could install nine turbines at this location and generate nine times 1500 kilowatts of power. Those nine turbines would not cause any power quality problems, would not cause any overload problems, would not cause any operating voltage problems. So essentially we could utilize the existing distribution grid for integrating, you know, about 13 megawatts of power or so without making any major significant upgrades to the system.

So we did this throughout their whole system. And this is the system again. And it's a little hard to see but there's little black dots that represent 1500 kilowatt wind turbines. And you can see that the wind turbines are clustered around the substations. The substations are shown in blue and they're labeled; like Fleming is in the middle. So the Fleming substation right there is I guess the substation's actually right below the town of Fleming there. And you see Fleming has got four turbine. Haxtun I think has three. Fairfield has four. And those are turbines we added to the existing system about, you know, spending any money on upgrading the system.

And a summary of all of those substations and the number of turbines that were added is shown on this table right here. You see the substations are listed on the left and you can see that toward the bottom it says, "Total number of 1-1/2 megawatt turbines added was 63 turbines."

And the limiting factors shown in the middle column there and is typically voltage flicker or transformer would be overloaded if we added any more; overloaded by carrying power backwards up to the 69. And in some cases it's just not very - for wind because there was not a suitable area for hauling wind turbines. But anyway I think it was a groundbreaking study and it did show that you can't put a lot of wind turbines on the distribution system.

So that concludes my presentation here. And I believe we're going to take some Q&A at this time. So, Garrett, were you going to handle that Q&A.

Garrett Shields: Yes, I was. It doesn't look like we have any questions though. I don't know. Maybe I wasn't clear in the introduction. But if anyone does have a question, if they'd like to submit it real quick right now, we can probably get to it. If not, we will just move on. And then if anybody has any questions for Tom, I think we can collect the unanswered questions at the end and either get back to you individually or post them on the Web site. So okay. Well thanks, Tom.

Tom Wind: Okay. I can hang around here until noon. So I'll stay on the line here in case some questions do come up before noon.

Garrett Shields: Well it looks like we just had a few here so we'll start with these. Let's see. Did the distribution of the turbines have a significant impact on the capacity factor?

Tom Wind: The distribution of the turbines have a significant impact on the capacity of the turbine I think that is - is that the first question? Is that the one from (Dorothy)? I guess, Garrett, I'm not sure I understand the question here. I'm scrolling down through the questions. Oh there it is. Did the distribution of the turbines? Oh okay. I understand the question now.

Garrett Shields: Okay.

Tom Wind: I assume this is referring to the Colorado study. And yes, where you put the turbines has a difference. And that's why we did the wind speed maps. We determined where the windiest spots were. And this is a fairly windy location. And so we located those turbines, you know, saying if anybody did this, they'd put it in the windiest spot. So we picked the windiest spots around and said if we put a turbine here, here and here and here, we calculated the capacity factor of those turbines and then made sure that we could connect it to the distribution grid at that point. So yes, it does make a difference. You always put turbines in the windy spots. Next question.

Garrett Shields: Next question, do you have any comments about types of generators at turbines such as YY or Delta Y?

Tom Wind: Types of generators and turbines. Well you don't really know - about any turbine that's manufactured will work on a distribution system. So the generator winding itself, lots of times those are ungrounded generators, three-wire - could be three-wire wide typically ungrounded. It doesn't really make any difference what the generator is. The only important part is the step-up transformer at the base of the turbine.

You know if you've got a 12.47 kV grounded Y system, typically you'll put a transformer in that is a Y - grounded Y on the 12.47 to match. Or you might be a Delta on the turbine side and a grounded Y on the other side. You know it just kind of depends upon the local distribution cooperative. But often times it's grounded Y on the 12.47 side. Next question.

Garrett Shields: The next question is, what is the impact of the wind generation on operating reserves?

Tom Wind: Well that's a question for the next speaker. I believe Clint will be talking about that. So I'll defer to him.

Garrett Shields: Okay. Okay that looks like that's about it for questions. If you have any others, like I said you can submit them and if you just - make sure to say that it's for Tom we can probably send them on to him.

Tom Wind: In fact, Garrett, I'll watch the questions right here and I'll respond. I'll type in answers here during the remainder period here to catch a few more questions. So I'll just do that online and I think everybody will see the answers.

Garrett Shields: Okay, great. Thank you. Okay next we have Clint Johannes. Mr. Johannes is a consultant serving as Assistant General Manager with Nebraska Electric Generation and Transmission Cooperative Incorporate in Columbus, Nebraska. He holds a B.S. in Engineering from the University of Nebraska Lincoln and an MBA from the University of Nebraska at Kearney.

He is licensed as a professional engineer in the state of Nebraska. Mr. Johannes' responsibilities include assisting the General Manager and administering power supply contracts in other matters for 22 rural electric systems with a total peak demand of over 800 megawatts in over 3000 gigawatt hours of annual sales.

Mr. Johannes worked several years for Nebraska Public Power District in various management positions including planning, regional operations and fossil production. He has also participated in a number of statewide activities such as the Nebraska Legislature Electric Industry Study Taskforce, the Nebraska Power Review Board Industry reviews conditions (unintelligible) annual reports, the Governor's Water Policy Taskforce and the Nebraska Power Association's Joint Planning Subcommittee.

Mr. Johannes is the Past Chair of the Technical Review Committee for the Nebraska Statewide Wind Integration Study. And he is the current Chair of Nebraska Power Association's Joint Planning Subcommittee. Go ahead.

Clint Johannes: Okay. Thank you, Garrett. Good morning everyone or good afternoon; whatever the case might be. We'll be talking as Garrett said this morning about the Nebraska Power Association's Statewide Wind Integration Study that was recently completed. Just a little bit of background about who the Nebraska Association is.

It's made up of voluntary members. All Nebraska utilities are involved either the public (unintelligible). And as you may or may not know Nebraska's a totally public power state. The NPA is a forum to discuss the common issues among the utilities and establish common positions and to do - prepare reports and studies, some of the ones that I'll be talking about today.

The study background - the study began in October of 2008 and it was put together through a contract with DOE NREL. There was a Technical Review Committee established that guided the process and provided input to it. We hired two consultants -- one is Interax.

And Interax is a firm that has considerable experience in wind integration studies. They were involved with the Eastern Wind Integration and Transmission Study as well as many others, the Minnesota study and others. Syntax was also hired. And they of course are the firm that does the production model and they have (Pro-Mod) and other production modeling tools.

The Technical Review Committee that was established included Nebraska utility members, members from the major utilities as well as the smaller ones. One particular member that I'd like to point out of the utility members is Doug Callison with NPPD -- the Planning Manager with NPPD. And he's here with me this morning.

And we get into the Q&A later he can help me with that part of the discussion. He was very active in putting the thing together. Consultants as I mentioned were Interax and Syntax and you can see the people that were involved there.

The review committee also had a wide variety of experts and stakeholders. And I don't know about the rest of the review committee, but I was quite proud of the level of expertise that we were able to put together and the effort that they put forth to help make the study a good one. We had in addition to the formal experts we had another 31 that we called observers that aren't listed here. But they were allowed to provide input and they were provided with all the information along the way.

Then of course we had the NREL subcontract officials, Brian Parsons and Neil Wikstrom. The bulk of the study as identified in the contract with NREL was to identify the cost and operating wind at 10% of higher penetrations, identify the production costs when operating existing generations under several magnitudes of wind penetration, identify reserves, identify if a federal hydro system could help with integration and then allow stakeholders beyond utilities to have input and participate in the study, which of course was the Technical Review Committee.

The key assumptions, we used the NREL meso-scale wind data for years '04, '05, '06 and then we put together the NPA load patterns for those same years and then of course (unintelligible) the load patterns to 2018 and used the loads and generation transmission system in that time frame. The area we studied was the NPA, all of Nebraska of course and remember most of Nebraska is in the eastern interconnection with the exception of about 1% or 2% of the load in extreme Western Nebraska, which is in the western interconnection.

We also looked at parts of the rest of the eastern interconnection as a part of the modeling. We looked at wind penetration levels of 10%, 20% and 40% of energy. And the purpose was to determine integration costs due to wind variability and uncertainty on a region-wide basis.

We used $25 to (ton) for carbon and did we run several sensitivity cases. Excuse me. When we put the TRC together what we decided to study in more detail was as I said the 10%, 20% and 40% and we looked at the 20% case both with and without the FBP EHB 755 kV overlay. So we ended up with four base cases.

That resulted in Nebraska mounts of 1.2, 2.5 and 4.7 gigawatts. The rest of SPP was 6.3, 12.6 and 25.4. As perspective the 40% case, which is a total of 30.1 gigawatts, would represent 59 wind farms in Nebraska and 318 in the rest of SPP assuming that they were about a 80 megawatt size, a considerable amount of wind. The wind level in the rest of the eastern interconnection was modeled per the EWIT Study and that's about 50 gigawatts and was about a 6% penetration level.

We used as a I said the meso-scale data for the years '04, '05 just as a depiction of some sizes of the farms. We put together typical farms. We didn't - it's not a siting study. We just put together typical farms so that we could analyze what the integration costs were. What drives the analysis of course is that the variability of the wind and the variability of the load. And of course you can see as spotted here in the red as the wind goes from zero up to 2000 in this particular case. And of course the load varies throughout the year and the day.

The penetration levels in a little more detail on this chart. So the NPA at various levels. The rest of SPP and then of course the main to the eastern interconnection was the same level -- about the 6% level -- that was used for all penetrations, 10%, 20% and 40%. The capacity factors as you can see are about 41%-42% at all levels.

Wind integration class, how is this determined? Basically they added the production costs to operate dispatchable generating units with the wind added -- of course wind is variable; it's not totally predictable -- along with the load which is also not predicable. Then using two production models, one with the actual -- it's not predictable -- and the other as a proxy and took the difference to determine what the integration costs would be on a dollar per megawatt hour basis.

The cost of increased reserves to manage wind is also due to the variability, uncertainty are part of the costs between the simulation for actual and ideal. The one thing to point out the integration cost doesn't include capital operating costs or costs of transmission and there are some other impacts of course that aren't included.

We looked at a couple of different proxy samples that try to get a handle on what the integration costs actually were. And this is just an example of one of those. It's a sub-block period. In other words it has blocks on peak and off peak. Some of the findings and conclusions, you see there's what the integration costs. Blue is the 10% penetration. Red is 20% penetration in this case without the overlay.

And you can see that the proxy used - the shape proxy basically is just capturing the cost of regulating reserves and windfall cast error. The sub-period block proxy includes some shape costs. And then if you look at the far right, that would include what we refer to as implied costs. And this would include some of the costs that are actually to be referred to as exported costs. In other words some of the integration costs that are picked up by utilities outside the Southwest Power Pool.

Again some more of the findings and conclusions. In terms of capacity credit by wind farm - and these are based on the current SPP rules. And they point out that there's I think some (NERF) standards that are forthcoming that would - they'll likely change. But the levels that were determined for capacity credit as you can see are fairly low -- six-hundredths of a percent for one found in (unintelligible) in July. Another example is 2.41% is the maximum as found at a 600 (unintelligible) plant in July. And these are for wind plant capacity credits.

Transmission. There was just not a transmission planning study. But it was necessary to make sure we had adequate transmission so that the models would solve. The wind sites were chosen as samples and permitted sites. But they were chosen to get some geographic diversity as well as to pick sites that had good capacity factor. And (unintelligible) SPP additional transmission is needed to get the wind to the load (unintelligible) various penetrations and it was of course the collective system.

We used a - using short-term plan Nebraska and SPP additions in a little better in the plan were used. And we also used the conceptual 765 kV overlay as I mentioned earlier for one of the 20% cases and the 40% case. We also used the sensitivity - did a sensitivity for Nebraska just with a 345 kV overlay. Excuse me. This map shows the conceptual overlay that we used for the 765 kV overlay in the second 20% scenario -- Scenario 3 -- and the 40% scenario. (Unintelligible) considerable 765 throughout the Southwest Power Pool.

So the findings and conclusions in terms of Nebraska transmission system, new transmission system obviously would be required to bring any significant resources online. The transmission system of course would be stressed with penetration under these (unintelligible) of course. The transmission system expansions must be designed with wind in mind to minimize those stresses. Specifically the transmission system shows increased (unintelligible) risk as penetration increases -- an obvious conclusion.

More findings and conclusions. In terms of wind generation curtailment, we found no curtailment in Nebraska based on the system that we were modeling. However in the Southwest Power Pool there was a 2% curtailment at the 10% penetration, 7% at the 20%, no curtailment at the 20% Scenario 3 -- of course that's a scenario where the 765 is in place -- and then 5% curtailment at the 40% level -- again this is SPP.

Incremental transmission costs for each of the scenarios is shown. The column on the right is the investment. And then the annual cost is shown in the middle column. At the 20% overlay for example, the investment is $7.8 billion.

The regulating reserve. The reserves were calculated outside of the production models. The production models of course are hourly models. And you can see that the regulating reserves required for wind generation become significant. You see the red numbers. These are the numbers that depict at each penetration -- 10%, 20% and 40% -- the Delta. In other words the increase in reserves required for the wind; about 500 megawatts for 10%, about 1000 at 20% and 2000 at 40%. This is the total Southwest Power Pool.

The ramp rates we were able to pull from the models what the changes in ramp rates -- ramp up and ramp down. Of course when wind and load are going in opposite directions at times you could get significant changes in ramp rates. And you can see in this table the red numbers show some of the significant amounts that were pulled out from the production models.

For example in the winter with low max, the up ramps maximum were - the load were 643, but wind net load went to 1113. Down ramps for example, you can see the red one in the fall down to load max with 718, but load net wind -- and that's just the wind -- is down another 1000.

More findings and conclusions, as you'd expect as the wind penetration increased the exports increased. Looking at SPP which includes Nebraska in this case increasing exports by half of the amount of the wind generation. So about half of it was exported. Probably some of this was caused by the fact that I mentioned earlier that the wind penetration in the external systems was held constant but the SPP penetrations were allowed to increase. And they were held constant at about 6% or 7%.

We modeled some difference CO2 emission levels and from this found that a pure price penalty CO2 was not an effective or was not very effective at reducing CO2 emissions in Nebraska. And probably the reason is because in 2018 there was no expansion to the existing generation fleet or export market. Penalties need to get to be significant before it changes and has more significant gas resources to be committed.

More findings and conclusions, I recall one of the contract suggestions or requirements from NREL was to look at how the federal hydro system might help to mitigate the integration costs. And we did some modeling but it was limited to how we could model because we didn't have the capability to model the river flows, but did model Nebraska and WAPA in different modes. The mode we're in now where energy is taken proportional on a little pattern more or less and model that's been taken on a low net wind pattern not increasing the energy but just increasing the - or excuse me, changing the time on that energy was taken. And we determined from this that there could be about a $1 million saving per year in 2018 dollars.

It needs to be pointed out however that when we modeled this we were modeling just Nebraska and WAPA. So if Southwest Power Pool were modeled in this same event, a good part of the benefit would probably also come from the Southwest Power Pool so the - just from the WAPA and Nebraska combination were somewhat exaggerated because we didn't allow the Southwest Power Pool to be a part of that. So it would be somewhere between - well actually zero and $1 million and probably toward the lower side of that.

Some additional things that need to be pointed out, there are additional costs to managing wind generation of course that we didn't try to capture. There would be additional maintenance and (unintelligible) rates and some D rates because of the way the fleet would be operating - different mode of the operating.

There's a lot more ramp up, ramp down. It'd be harder on the equipment. There's also the degradation of heat rate from ramping and cycling. It wasn't included. It's very difficult to get a handle on. And there would be expected to be some increase in emission rate per megawatt hour production and that wasn't calculated as well.

By way of summary, looking at in this case as were on some of the previous charts the 10% penetration and the 20% penetration, these are in 2009 dollars using the (unintelligible) proxy. Again this is basically - this accounts for the added reserves and the wind error (unintelligible) that's a $1.39 at 10%, $1.45 megawatt hour at 20% -- excuse me. If you use a sub-period block proxy that changes to $1.92 and $3.11. And then if you use the (unintelligible) what we consider exported costs it goes to $5.41 and $9.26. It's noted here the if you look at $5.41 that's probably about 10% added cost to the wind generation side (unintelligible).

Incremental transmission investment, 20% cases I pointed out earlier that was (unintelligible) $11.8 billion. And the capacity credit value goes from like six-hundredths to about 2.41% of nameplate. And this presentation as well as the executive summary and the full report are on the Alaska Power Association Web site. Garrett, that would conclude my presentation.

Garrett Shields: Thank you, Clint. And any questions you have for Clint's presentation you can just keep adding them to the question queue and we'll get to those along with any questions over Paul's presentation at the end of the Webinar.

So our next speaker is Paul Denholm. Dr. Denholm's a Senior Energy Analyst in the Strategic Energy Analysis Center at the National Renewable Energy Laboratory where he examines system integration of renewable electricity generation sources such as wind and solar. He holds a B.S. in Physics from James Madison University and an M.S. in Instrumentation Physics from the University of Utah and a Ph.D. in Environmental Studies in Energy Analysis from the University of Wisconsin in Madison.

His research interests include examining the technical, economic and environmental benefits and impacts of large scale deployment of renewable electricity generation included in the school of enabling technologies such as energy storage, plug-in hybrid electric vehicles and long-distance transmission. Paul?

Paul Denholm: Thank you. Energy storage is an increasingly potentially important topic and something that we get a lot of questions about here at NREL looking at the role of storage and integrating renewables. And we get a lot of questions - and one of the common questions is if energy storage is so great, why doesn't more of it get built considering the fact that we've got 20 gigawatts of pump hydro? But we really haven't seen much activity in the last couple of decades beyond this increased interested.

So a lot of what we do here is look at the value of energy storage in different renewable energy scenarios and really try and understand the value proposition as well as understand how can you, you know, do analysis properly to make sure that you capture the multiple value streams of energy storage. So what I'll be talking about today is focusing not just on the individual technologies, but really the challenges of properly valuing energy storage in electric power system.

I will be talking about some of the technology characteristics given, you know, considerable uncertainty about the status of the technology, especially with a lot of the emerging and kind of pre-commercial and semi-commercial products such as flow batteries and some of the other battery technologies. And finally some perspectives on the role of energy storage with renewable energy.

But really I think we need to start with talking about what is the basic value of energy storage and how do you understand what that value is. So there's a lot of papers out there on kind of the multiple value streams. (Jim Ayer) just released a good report contracted through (Sandia) -- and if you email me, I can forward you a copy of that report -- basically discussing the multiple value streams that you can get from energy storage and some of the complications of understanding and actually quantifying those values.

But in terms of the primary sources of value you see them kind of sliced and diced in multiple ways. But here's a list of four general categories from capacity, load leveling or arbitrage -- this has lots of different names -- various ancillary services and then deferral or increasing the utilization of your transmission and distribution assets.

Now the first and often only value that a lot of people look at is the value of load leveling or arbitrage. Depending on whether or not you're in a regulated market you might call it different things. And this is just a sample of some wholesale values. I think this is from PJM. It doesn't really matter.

You're all familiar with the fact that the price of electricity varies hourly and seasonally. And depending on whether or not you're in a regulated market you can use your load lambdas or the wholesale market day ahead or spot market prices to get an understanding and ultimately a valuation of what the value of buying off peak energy and then selling it on peak is.

Now a lot of people look at energy arbitrage. And there's been a number of historical studies. And using wholesale market data you can do some simulations and get an idea of what the value of an energy storage device is.

And here's a summary of some studies and I can forward you these studies; most of them are in the public domain in some form or another and looking at PJM and New York and California and the various markets for either bulk energy supply -- again buying off peak and selling on peak -- or providing the various regulation or contingency reserve services depending on the market.

So you know it depends on obviously if the market has services -- and of course these all go by different names -- but regulation would be your frequency regulation. And then contingency reserves, in some markets this would be called spinning reserves but this is rapid response.

And you can get an idea of - do simulations, get an of what you would have gotten had you bid in an energy storage device with certain characteristics into these markets. And then you can calculate well given an annual value, what would be the break even cost? Or how cheap would a device had to have been? And this chart translates these historic market values into prices.

And the important point of this graph is that when you're looking at - especially arbitrage only or perhaps spinning reserve you're looking at a device that is somewhere not much more than $1000 per kilowatt depending on your capital charge rate. This is an extremely simple financial analysis basically using just a fixed charge rate. This doesn't really - this isn't a very sophisticated analysis but it does allow you to get some basic idea of well how cheap would an energy storage device have to be to break even on those costs from those markets.

Now you also see that if you're talking about frequency regulation, it can be a lot more expensive device. Frequency regulation being a much more valuable service which is why it's possible to have a more expensive device and make money off of that. The best example of that is the flywheel which is certainly more than $1000 per kW. But given the high cost of regulation in the New York and some of the other markets it may make sense to deploy those.

Now of course frequency regulation is also the highest demand service in terms of its technical requirements; being able to rapidly respond to a signal from the ISO to increase or decrease output rapidly. So not all storage devices -- particularly those mechanical devices -- may be able to completely meet the requirements of a frequency regulation market.

So now one of the important things about energy storage analysis and I've seen this with a lot of utilities, they basically start and stop with a basic arbitrage analysis. They take their load lambdas or their system-wide production costs and they stick it into a spreadsheet and come up with again those kinds of numbers -- well storage device has got to cost $500 per kW or $800 per kW.

And when you do that analysis and you stop there I can pretty much guarantee you that you're not going to find a storage technology that is going to be cost effective. So if you're just looking at energy arbitrage, you don't - I can tell you, you don't have to do the analysis because you're not going to be able to buy a device that can meet those requirements with the potential exception of CAES, which is by far a compressed air energy storage which is by far the cheapest energy storage device.

But the important thing about a valuation of energy storage if you really want to consider it as part of your capacity mix is to make sure that you capture the multiple value streams. And this is historically difficult because a lot of the production cost tools don't allow you to do all of the things in the simulation that an energy storage device actually could do. Primarily of course you have to capture its capacity value. If you have a device that's capable of an eight-hour or more continuous discharge, you can certainly count that towards firm capacity.

But more importantly or equally importantly is making sure that you capture the other values. Now when you do load leveling or arbitrage that will reduce the cycling on your units. And depending on how you - what day do you have available to capture effects on part load efficiency or the O&M costs, that may or may not be captured in your calculation. And this is something that keeps coming up in these wind integration studies that's of particular concern to the utilities; that is what is the cost of cycling? And unfortunately we just don't have a good idea. We haven't done enough studies on what the impact of all these -- especially coal plants -- effects of O&M - increased O&M will be when we start cycling them more.

Equally important is also the ability of these devices to provide ancillary services, the ability to decommit units that may be providing some form of operating reserve and that could be equally provided by energy storage devices. And kind of the easiest way to give an example of that is thinking about a pump hydro device and what a pump hydro device can do for you while it's pumping.

So while it's using - while it's pumping in the middle of the night you can turn that device off. And even if it's got a 15-minute turnaround and can't start generating for a while, that reduction in pumping does represent a source of spinning reserves.

So if you can basically capture the value of the energy storage devices to provide multiple services -- and that doesn't mean double count. I mean obviously if an energy storage device is discharging for energy services, it can't also discharge for spinning reserve. But if the software can capture the ability of energy storage devices to provide multiple services, decommit thermal units providing operating reserves, there's a substantial value there. Unfortunately that value can be difficult to capture depending on the limitations of the production software.

One of the other very important aspects of energy storage that is also hard to capture is its benefits to both distribution and transmission systems. You can avoid infrastructure, you can avoid congestion costs by strategically placing energy storage devices. And this is one of the primary applications we're seeing for small scale energy storage devices. American Electric Power is deploying sodium-sulfur batteries for that very purpose. If you've got a distribution system - distribution feeder that is near its limit and you're looking at a large capital investment for a lumpy investment -- and this is a classic problem with distribution networks -- you've got a small increase in demand and you've got kind of a fixed increase in size, perhaps you can avoid that big lumpy investment by placing a storage device at that location.

That is obviously a case-by-case analysis and obviously a production cost model isn't going to capture that. It's the distribution engineers that are going to have to go out there and figure out which distribution substations are candidates and do the cost benefit on a storage device versus new distribution infrastructure.

Okay so in terms of where we are with utility scale storage, in the U.S. it's basically all pump hydro. We've got about 20 gigawatts and about 100 gigawatts worldwide; so a well-proven technology. Round-trip efficiency, AC to AC round trip efficiencies routinely exceed 75%. Beyond that we're really almost getting into the margins here. Two compressed air plants, the last one in the U.S. built in 1991-'92.

A lot of interesting compressed air technology because really in terms of bulk energy storage it's really the only technology that is really perceived as an economic competitor to pump hydro. So you're looking at a lot of proposed plants as well as demonstration projects that are proposed or being developed. Probably one of the most interesting -- I'll talk about this a little bit more -- is the one in Iowa.

In terms of batteries or other technologies it's really just a bunch of demonstration projects and proposals with the exception of about 270 megawatts of sodium-sulfur batteries mostly in Japan offered by a single vendor, NGK, who's also provided the sodium-sulfur batteries for utilities in the U.S.

So as I mentioned earlier there is this renewed interest in energy storage. And really it's the combination of a lot of different things. First of all the establishment of energy and ancillary service markets has really given price exposure, especially in the ancillary service markets where people are seeing extremely high value for these ancillary services and the ability of capacity devices to provide ancillary services. That's one of the big drivers behind

Beacon and their flywheel projects as well as a number of other proposed projects.

Now a lot of the other interest is based on the widespread belief that wind and solar need energy storage to make significant contribution. And so a lot of people are trying to figure out well how do I make money on that. And that is really the challenge of all this is how do you take advantage of the variability of wind and solar to make money.

And one of the problems of course is that the value proposition has yet to emerge. The markets to take advantage of these services - whether or not it's completely captured in energy and ancillary service markets or whether or not new markets have to emerge to deal with variability.

There have been some technology improvements and some new technologies, some funding opportunities of course with a lot of the DOE grant programs and all the various programs going on right now, both at the state and federal level. And then we're seeing something very interesting happening in the legislature, both at the national level and the state level, which is energy storage standards. So proposed in California and we're seeing some action in the fed as well that actually mandate storage requirements. So that's interesting and we'll just kind of have to see how those play out in terms of whether or not they pass and what the implications are for large scale energy storage deployment.

There are a lot of charts available. The Electricity Storage Association has an excellent Web site that provides lots of these types of charts that show you the landscape of energy storage. And they'll compare the time of discharge with capacity or relate the energy versus capacity so you can kind of slice and dice the energy storage technologies in multiple ways.

Commonly - and there's no kind of uniform definition of this, but commonly energy storage technologies are classed in three basic categories. And again they can be sliced and diced different ways. But this particular set of categories are in the power quality range where you have short-term kind of minute level discharges.

Best example would be frequency regulation. Bridging power, that's kind of an older definition. But the best way of thinking about that would be either a device for a contingency or spin. Of if you're thinking about it in terms of the wind or solar world, you might consider this the amount of time it takes you to start up a quick start unit.

So the best example being what's happened in ERCOT at least once with not incorporating wind forecasts into their planning - into their commitment and dispatch process, they've been left short a couple times. Now that's changed now because now they're incorporating improved forecasting. But if you don't have good forecasts, you don't have as much wind as you thought. You may have to start up some quick start units. And energy storage could provide kind of a bridge in the time it takes to start these units with a discharge of up to an hour. And then kind of the bulk energy storage being hours of discharge. And that's the area that's dominated by pump hydro and CAES.

The actual bubble chart beneath the description of the categories provides you an example of what storage technologies have actually been deployed for those services. So this isn't kind conjecturing about what would happen in the future. This is actually things that have either been deployed in the field or at least proposed to be deployed in the field.

So there are a number of battery technologies. But again most of these batteries are kind of one-off or demonstration-type projects. You know the 20 gigawatts of pump hydro is, you know, a factor of 100 more or a factor of 10 to 100 more than all the storage technologies deployed in the U.S. Combined with the exception of that single CAES plant.

Okay. So in a little bit more detail about what's available right now. For power quality right now the fielded systems is really flywheels are the one that appear to be taking the lead in terms of economics. Historically there's been a lot of interest in various technologies and you can go back into the literature.

And big pushes by DOE R&D programs for capacitors and superconducting magnetic energy storage along again with some demonstration projects. But in terms of actual deployments that appear to be economic -- you know plus or minus given some incentives -- Beacon has kind of taken the lead with their flywheel. And they're targeting those places in the U.S. that do have regulation markets, so New York and New England also potentially California.

Again, to deploy this in a place where you're not in a wholesale market you've really got to be able to understand what is the cost of frequency regulation to your system. So do simulations and see okay if you can decommit or reduce the output of thermal generators providing frequency regulation, what is that really costing my system in terms of opportunity costs, in terms of decreased heat rates and increased emissions, increased O&Ms. And again those are tough calculations to make which is why, you know, you're unlikely to see flywheels deployed in any locations in the U.S. that do not have wholesale markets for frequency regulation.

For bridging power, again discharge times of up to an hour. Right now demonstration projects again. You've got things like a big battery up in Alaska for frequency or for spin. They didn't have spin in their system. Their spinning reserve up near Fairbanks was actually shedding load and customers weren't really liking that.

So they got some money to install a big 40 megawatt battery to provide spin and that's been successful. But again, whether or not that's economic is depending on what the type of the system is. And we haven't seen, you know, other economic deployments of batteries for these applications.

So battery technologies right now are still focused on mobile applications. And the lithium-ion particularly being - while we have seen a demonstration project, there's a one megawatt lithium ion battery deployed in PGM for frequency regulation.

And most people focusing on lithium-ion are still focusing on the vehicle market. That is perceived as the big winner in terms of making money on lithium. If the costs come down as lithium gets cheaper -- primarily again for vehicle applications, there would be of course the potential opportunity for stationary applications.

And people are also looking at things like using old EV batteries after their five-year life or whatever, deploying that for stationary applications. Again, since we haven't seen any real deployment of EVs yet it's going to be a long time until there's a large supply of used EV batteries.

But it's certainly something to keep an eye out for as the costs continue to decrease. But we're obviously not there yet. It's going to be some time. And again the vehicle market will probably dominate both the R&D - the targeted

R&D and the deployment for lithium-ion. But we'll have to keep an eye out for it.

For energy management, again this is bulk discharge, multiple hours. A lot of these technologies can provide multiple services. And this is something I should have said for the bridging power. If you've got a device, especially a battery that's capable of providing 30 minutes of discharge primarily for something like a spin or contingency reserve, it may also provide frequency regulation as well -- as long as we avoid double counting.

Likewise an energy management battery can also provide power quality services especially if you've got a high-energy battery such as sodium-sulfur with very fast response. Perhaps less likely or less suitable for pump hydro or CAES -- although with variable speed drives in pump hydro and the new compressed air design that does not involve a single turbo machinery train, you could potentially provide ancillary services as well. And I'll discuss that a little bit more. Another technology to watch I think is thermal storage -- end use storage. It's been somewhat ignored. But I think there's a real potential there as well.

Okay. So just to get in a little bit more detail about these technologies, I've mentioned pump hydro storage. Again nothing really new here other than the fact that there's still a lot of continued interest. And the thing that I think is very interesting to note is there's about 30 gigawatts of proposed new capacity. So more proposed capacity than existing capacity. Now again, we all know that that's not all going to get built. A lot of this is just kind of proposals.

But the fact that there's this level of interest I think reveals a lot about the fact that a lot of people say, "Well pump hydro, all the best sites are used.

Environmental opposition will prevent any new pump hydro getting built." The fact that people have taken the time to propose 30 gigawatts of new capacity I think shows that this technology's not dead; there's a lot of potential here.

Compressed energy storage is the one that a lot of people are focusing on just because it's really the only bulk - low cost bulk alternative to pump hydro. If you're not familiar with compressed energy storage, it is a hybrid technology.

It involves a gas turbine where you basically precompress the air for a conventional gas turbine more or less. It does require very large volumes of air. So we're really talking about an underground formation. In the U.S. this has been a dome of salt. Basically a big salt dome that you pump water in, you pump the brine out and you're left with a big hole - you're left with a big cavern; that's the Alabama plant.

Since it does involve a gas turbine you can't really define a single point efficiency. So classically we might say a pump hydro device would have a 72% roundtrip efficiency. You can't do that with CAES. It's got electricity in and then you also have a heat rate. Now that heat rate is very low because the energy that's required to compress the air is coming from electricity. But again in the model - if you were trying to model that, you've got to put in both the electricity consumption and the natural gas burned.

A number for those facilities, the one that's maybe of most interest for utilities in the Midwest is the Iowa Stored Energy Park. Some information about that on the Web. Also a bunch of nice people involved in that program that would love to talk to you about it. Other proposed projects, Pacific Gas and Electric.

There's also proposed plants in New Jersey. And then a plant that's been proposed for a long time in Ohio that's kind of on again/off again -- the Norton Project which is very large that would use an abandoned hard rock mine. There are some alternative designs that don't use fuel. But those are more academic. So in terms of near-term deployment the kind of standard CAES would be what you'd buy.

Again here's some graphics that I stole from the Iowa Storage Energy Park. One of the nice things about that is at least they've published their turnkey prices. Now estimates for CAES, you're going to see a lot of different estimates. But they tend to be in the $600 to $1200 per kW range depending on whether or not it's aquifer-based or salt-based, which is a pretty wide range.

But Iowa was getting a turnkey price - this is about four or five years old now, but turnkey price of about $870 per kW which does make it competitive for basic energy services -- a combination of firm capacity as well as load leveling. So again that's another reason why people are so interested in CAES. It's really the only technology out there that's below the $1000 per kW mark.

And the unique thing about the Iowa project is it would be using an aquifer which would be the first time that's happened. The other two CAES plants -- the one in the U.S. and the one in Germany -- being deployed in salt.

A lot of uncertainty about CAES geology. There is some work that has to be done and this is sort of outside the kind of standard utility siting process. It involves this hiring of geologists to characterize. I've got a quote there from someone involved with the Iowa project basically saying that this is not a trivial exercise.

While there's a lot of aquifers out there it's certainly not clear, you know, how many of them are suited. However, you know, given the interest in CAES there's a lot of effort being done and to further characterize these. And the last time I heard from Iowa they had arrived at what they believe is suitable geology for the Iowa Project.

In terms of batteries for high-energy applications there's really two classes; one being the high temperature battery. The most widely deployed being the sodium-sulfur battery. There are some other chemistries. But in terms of something you can actually buy, the sodium-sulfur from NGK is really the only thing out there that you can actually deploy on a turnkey basis. The other competitor high-temperature batteries is a variety of liquid electrolyte flow batteries.

Now we've seen some limited deployment of these. There was a 50 kilowatt deployment of a vanadium redox battery. The vendor who provided that has since gone out of business. A lot of these batteries were emerging right around the time of the economic crisis. So we've seen some of these companies go out of business after limited deployments. Some other chemistries that you can get, zinc-bromine. These really are in the early commercialization stage.

And I haven't provided prices because we don't really - in my opinion don't really understand what these prices can be in large scale. So if you're interested in these batteries, you're really going to have to talk to the vendor. And again, the Electricity Storage Association has an excellent Web site.

They've got links or the names of some of the current vendors that they keep updated. The vanadium redox battery technology was purchased by another vendor. So it is still possible to get this but we're not seeing, you know, large numbers of deployments here in the U.S. So again, it's a matter of contacting the vendor and see what they will offer you.

Now there have been deployments in other countries. So it's not like the fact that there's no deployments in the U.S. means there's no deployments anywhere. But again that has to be considered when you're really talking about the price.

And I would warn anybody when they look at these prices, especially on these kind of pre or early commercial stage batteries, take them with a grain of salt. You know does that price - is that a turnkey price? Does it include the power electronics? Does it include the cooling? You know there's a lot of due diligence that has to be done with a lot of these early commercial products.

One of the things that I think is worth looking at and that does not fit into the traditional electricity storage technology class is thermal storage. And in particularly energy storage in buildings. Now your peak demand in most of the country is going to be driven by air conditioning. So if you're talking about an energy storage device with a large capacity component to it -- meaning you want to buy an energy storage device not only for load leveling but also for firm capacity -- thermal storage does fit that. If you're peak demand is driven by air conditioning, you can shift energy by making ice or cold water off peak and then releasing that cold energy during on peak. And it is functionally equivalent to electricity storage during that cooling season.

Now the roundtrip efficiency of these devices can be very high. When we talk about roundtrip efficiencies for conventional storage technologies like batteries or pump hydro it's pretty rare that we can exceed 75%. Yet the roundtrip efficiency from thermal storage can actually be near 100% in some of these applications. These are commercially available products. And while they’re not - they don’t fit into the kind of the central bulk planning framework, they can be dispatched the same way essential plant can be dispatched.

One of the primary advantages of thermal storage -- especially end use thermal storage -- is not only firm capacity but firm capacity at the end use which means you’re avoiding all the transmission and distribution losses which at the time for peak demand can be very high.

They also act as distribution replacement or deferral of additional distribution assets. Now they are tied to specific use so it’s more difficult to compare these. Again it’s tough to put these into (Pro-Mod) or whatever your unit commitment software is. But again it’s worth looking at.

A couple of caveats. I’ve mentioned a lot of these already. But again when you’re talking about efficiency these aren’t uniformly defined. You have to be really careful when you’re talking to the battery vendors to make sure they’re talking about the AC to AC roundtrip efficiency. You have to make sure that they include the parasitics. NGK is good about this.

There are energy demands associated with keeping the sodium-sulfur battery hot. But there are other parasitics, especially with some of these batteries like cooling requirements of both the battery and the power electronics; make sure those are considered. Again CAES does not have a single roundtrip efficiency number. And then again with costs, you know, are you talking about the complete system including the engineering. You know are we talking about a prototype or a mass-produced device.

And the other thing of course is that for an energy storage device you’ve got an energy component and a power component. Now we’re all used to talking about dollars per kilowatt, but for a battery it’s got an energy component and a power component. So you may be talking about a one kilowatt battery with a two-hour discharge time or an eight-hour discharge time. Those additional kilowatt hours cost money.

So again to do a comparison if you’re comparing an energy storage device to a come on cycle or a peaker, you need to make sure that that dollars per kilowatt includes the energy component for a direct comparison. And it’s difficult to compare devices that offer different services. So for a flywheel you’re just not going to have a whole lot of energy. It really is a capacity device that’s going to offer frequency regulation or maybe some contingency reserve. But again it involves an appropriate comparison of the technologies for the relevant application.

So kind of some general conclusions of the storage and the grid of today. Again not talking about renewable energy applications but just when you’re thinking about do I want to consider and energy storage device in a capacity expansion plan. Well we do see increasingly competitive technologies for things like ancillary services. But again it’s difficult to evaluate those and you have to make sure you look at the multiple services.

If we’re talking about bulk storage, there aren’t really any technologies right now that are going to beat pump hydro and CAES. But when you talk about applying technologies on the distribution side and taking the additional advantage of decreased losses and distribution asset deferral, several technologies are increasingly competitive including sodium-sulfur and thermal energy storage.

So again it's difficult to look at the suite of technologies available and say make general conclusions. You have to look at both the application specific and the location specific devices and potential applications and values.

Now when we're looking at distributed storage analysis, again all the same rules apply. We have to look at both the capacity services and energy services. You do need to look at marginal losses systematically. It's again better if you look at - instead of average losses if you can just use actually measured losses during times of peak to really look at what the energy and capacity savings are.

And then also congestion benefits and as well if possible look at actual peaker and power plant performance during periods of high demand. You know can you look at the decreased heat rate or decreased capacity during periods of high temperature.

If you have the ability to do that, you can really better evaluate what these energy storage devices can do for you. That's not easy analysis to do but if you're really going to capture the real economic benefits of these, it's highly recommended that you look at the entire suite of services and cost and benefits, especially during periods of high peak demand.

Now obviously a lot of questions come down to, well what about renewables and variable generation? What is the benefit of storage to those? And as I've kind of tried to indicate the analysis of energy storage in general is actually difficult. The analysis of energy storage and renewables is just that much more difficult because you're starting with your existing system and all of the benefits that energy storage can provide, well they can provide that and more when you increase variable generation.

But that analysis is difficult. You've got increased variability. You've got all of the issues of minimum gen points, all the additional O&M issues of increased cycling that are not well understood and really you need to consider all of those issues and all of the competitors to energy storage when considering variable generation.

So one graphic that I like to show is basically this issue. And this is really the ultimate issue that a lot of people are going to face with large deployment.

And that is this MinGen point. The fact is you can only back off your base load plant so much before you run into plant stability and other issues. And it's just not - this is really challenging. And especially given the fact that we do get to see a lot of wind blowing during periods of relatively low demand. And so the question becomes, what are we going to do with the energy that we may not be able to use from wind? If we can't back off our generators, what are we going to be able to do?

And this is really kind of the list of options. You can add additional load. You can increase flexibility in the system. You can shift load. And you can supply shift via energy storage. And all of these technologies are options. And so what a lot of people are talking about right now is the idea of a flexibility supply curve where you consider all of the options to increase both the ramping characteristics of your system, the rate of which they can ramp as well as the range at which they can ramp and evaluate all the technologies, including increasing the flexibility of your existing generation and deploying multiple storage technologies.

And that's kind of the framework that I like to leave with people to think about the role of energy storage. It's just one piece of the flexibility puzzle that is going to be needed to deploy variable generation at large scale. So basically in conclusion I've already talked about this in detail so I won't go over these bullet points any more. But I must leave it with a single point that I've tried to emphasize is that if you're going to look at energy storage, you really do have to look at multiple services for it to make sense.

And that's the end of my presentation. And I can take questions now.

Garrett Shields: Thanks, Paul. Let's see. So we'll go to the questions now. We'll start with one here. It looks like it's for Clint. And I guess it's more of an overview question. Given all of the information presented, what does all of this mean?

Clint Johannes: I'm not sure quite how to answer that. I guess it means that there are - one thing it means is that there are costs to integrate wind. Wind is variable and uncertain and so there are additional costs to the generating transmission system. It'll operate in a different mode that increases its costs and we were trying to capture what those costs were. And you know as I showed it varies depending on which pieces of the cost you're talking about. In general it looks like it's probably about $5 a megawatt hour. Does that answer the question?

Garrett Shields: That's good. If they have a more specific question, they can follow-up.

Clint Johannes: Okay.

Garrett Shields: Okay. It looks like this one might be for Paul. It's my utility is planning a concentrated solar PV demonstration combined with energy storage. I expect this package in multiple 100 kilowatt system. What would be the best battery technology for load leveling ancillary services to this demonstration?

Paul Denholm: Okay so you're - just to make it clear it sounds like we're not talking about concentrating thermal power; we're talking about concentrating PV. You know if we’re talking about CSP, we’d be talking about thermal storage which I didn’t talk about. So we’re talking about PV. And so the concern with PV - one of the big concerns about PV right now is the ramp rates.

In general PV has good coincidence with demand. So the idea of shifting PV in today’s system doesn’t really make a whole lot of sense. But one of the big concerns is, you know, are there going to be ramping impacts on my system.

Now if we’re talking about, you know, a few kW, that’s more of an academic exercise because the ramping of a single PV unit compared to, you know, of a one megawatt system compared to a 500 megawatt system is not great. But you know as PV gets deployed more there is some concern that the ramping impacts of PV may be dramatic especially if we have - a kind of cloud transients. You can imagine a cloud front moving over a PV system and knocking out your PV output in a few minutes.

And so there’s certainly interest in deploying increased flexible resources to decrease that ramping impact. And again I wouldn’t necessarily - I can’t really pick any individual battery technology. I mean they all have the capability of ramping very rapidly. So it really comes down to what the cost is for the specific application. So for instance when you go to NGK and talk to them about their sodium-sulfur battery, they have multiple offerings. They have an energy - an offering that’s primarily focused towards energy. So you’d buy a one megawatt battery with eight megawatt hours of energy, so eight hours of continuous discharge. But if you were more concerned about ramping events, you might want to buy their offering where it’s a one megawatt battery with only one or two megawatt hours of energy storage. Because again it’s primarily suited for ramping.

But I'm certainly not in the position to pick winners at this point, you know, especially concerning the fact that these are not completely commercial products in the case of the flow batteries. They all - almost all these batteries or in fact all of the batteries have the capability of doing ramping and taking care of ramping events. So it really would come down to going to the vendors and seeing which one has the best cost and cycling characteristics for the application. That's it for me.

Woman: So we're having a little technical difficulty on Garrett's end. Just hold one moment please. Okay apparently they're having phone difficulties on Garrett's end so (unintelligible) questions. And I'll be tracking the questions that are coming in now and forwarding them over to Garrett for posting on their Web site as he mentioned earlier. I apologize for the technical difficulties. But I'll leave the Webinar Q&A open for the next ten minutes or so -- 15 minutes.

If anybody has any questions, feel free to post. If any of the other speakers - Clint or Paul, if you have anything else to add, you know, feel free to jump in now. If you see the questions and want to answer them directly, you are more than welcome to do so as well.

Paul Denholm: This is Paul. I'll just add one thing. If anybody's interested in any of the reports that I've mentioned, I'd be happy to email them out. We also have an overview report kind of discussing the basic issues around extremely high penetration of renewables and the potential role of energy storage that I would also be able to - be happy to send out to anybody that's interested.

Garrett Shields: Okay. This is Garrett. I'm back. I don't know what happened. I think our phones went down for a second there. I see another question here. Was this question already answered about the CAES system, the General Electric?

Paul Denholm: If it's a question about CAES, we have not had a question about CAES yet.

Garrett Shields: Okay. Then we'll continue on with this question. It is, how important could the General Electric ADELE AA CAES system being developed in Germany and the Danish (unintelligible) electric vehicle storage technology be in the near future in your opinion?

Paul Denholm: Okay. So the first question is about adiabatic CAES. And adiabatic CAES is a system that does not use natural gas. So one of the problems with conventional CAES is it does burn natural gas. So if you're concerned about the ultimate availability of the resource or a pending green house gas regulation or fuel price volatility -- and this is particularly a European concern.

So the Europeans obviously are way - you know more concerned about climate change and those kinds of issues. So they're not as interested in regular CAES. So they've spent some time and money looking into the concept of storing thermal energy and using that to reheat the air coming out of CAES.

Now nothing's been built. In my opinion it's still pretty academic. So I don't really foresee -- especially in the U.S. -- any near term deployments of adiabatic CAES. Now of course being at the National Renewable Energy Lab, we pay attention more to adiabatic CAES because it is a non-carbon source of, you know, generation. And while it's something interesting to watch, you know, if I was trying to site and build a CAES plant myself personally, I would be looking at the standard technology as it is right now. Because again the next CAES plant that gets built will be an incremental improvement over the 1991 vintage CAES. So we've got to deploy some new CAES - or kind of state of the art CAES technology now just to prove that and then maybe adiabatic CAES in the future.

What was the second - the second question was involving vehicle storage?

Garrett Shields: Ah, yes.

Paul Denholm: Could you repeat that question?

Garrett Shields: It was about the Danish (unintelligible) vehicles storage technology.

Paul Denholm: Okay I'm not familiar with that. We do work on, you know, plug-in hybrids and vehicle energy storage and basically entering those - in to those to the grid. And those are very interesting in terms of using controlled charging of vehicles.

We work both on just controlled charging can optimize - think about a vehicle as a dispatchable source of load. Obviously that would potentially be of great benefit to time the charging to periods of high wind output or normal load demand. Vehicle to grid is a little bit more controversial. We have done some work on that. But I'm not familiar with the specific technology asked about so I can't comment.

Garrett Shields: Okay. Thanks. The next question is addressed to Clint or Paul. And it is with low cost natural gas, what is the effect of quick start gas instruments for backing up wind?

Clint Johannes: This is Clint. I can give a comment in terms of the NPA study. With the NPA study we didn't add any generation. We had sufficient capacity in 2018 with the existing fleet. So there were no additional units added. However part of the integration cost is the fact that of course gas units can respond to the variability and uncertainty of wind much better than coal. So coal is back down and replaced with natural gas. To the extent that happens the natural gas prices are lower, the integration costs then would be some lower.

Paul Denholm: Yeah, this is Paul. I have nothing to add to that. That sounds like a good answer to me.

Garrett Shields: Okay, great. Another question. Should (Mycell), PJM, (Aircot), WAPA, BPA, et cetera provide a greater value for RECs generated without fossil or nuclear fuel -- i.e., the true costs and true value of renewable energy integrated directly or stored and generated on peak without carbon and other emissions in high level radioactive waste? And then...

Paul Denholm: That sounds like (unintelligible) to me.

Garrett Shields: And then there is - looks like they inserted like a certain value of REC zero emissions and zero waste versus a certain number of REC wind plus gas or coal or nuclear.

Paul Denholm: That's a pretty complex question. I'm not really sure that I can really touch that in a conference. I'd would be willing to exchange emails and give my thoughts on kind of the value, you know, valuation of RECs and things like that. But I'm not going to be able to touch that on this call.

Garrett Shields: Okay. And you can find that question in the Q&A queue. So if you wanted to exchange emails with that person you could.

Paul Denholm: Okay.

Garrett Shields: Let's see. Another question for Paul. Any potential of hydrogen fuel cells for load leveling?

Paul Denholm: I don't want to get myself into too much trouble when I talk about hydrogen. Hydrogen has a lot of challenges. Right now hydrogen is both very costly in terms of the electrolyzer, the storage mechanism and the fuel cells and it has very low roundtrip efficiencies.

The roundtrip efficiency - even a theoretical roundtrip efficiency of a hydrogen system isn't going to be more than 50%. I mean theoretically you can get more than that, but kind of theoretical practical you're looking at about 50% upper limit.

And that combined with a very high capital cost of all of the pieces - I mean again, one of the beauties of pump hydro or compressed air is, you know, you're using a very low cost medium to store the energy.

You're using a big hole in the ground whereas hydrogen you need compressed air cylinders or - there have been people that talked about underground formations and that has yet to be proven. But the fuel cells are very expensive. So a lot of - I think fundamental R&D work has to be done to get the costs down to the point where they're competitive with today's technologies.

Garrett Shields: Okay, great. Thanks. As of now it looks like that's it for questions. It looks like that it's for all the questions coming in. So I guess I want to thank all of our presenters.

And the presentations will be available in the near future on www.repartners.org along with all the past wind Webinars. So you can access them there. And any questions that might not have been answered or any questions for Tom that weren't answered, we will get those to him and try and get you an answer. So okay. Well thanks again and I guess that's it.

Paul Denholm: Thanks.

Garrett Shields: Thanks.

END