Integrating Expanded Wind into the Nation's Electrical Grid
June 19, 2013

Coordinator: Good morning and thank you all for standing by. At this time all participants are in listen-only mode. After the presentation, they will be doing question and answer over the Net portion only. Today's conference is being recorded. If you have any objections, you may disconnect at this time.

I'll now turn the meeting over to Mr. Ian Baring-Gould. You may proceed.

Ian Baring-Gould: Great. Thank you so much and welcome everybody to the June edition of the Wind Powering America Webinar.

This month we're focusing on integrating wind into the nation's electric system and we have two great speakers in regards to this, Steve Clemmer from the Union of Concerned Scientists. They just released a great report, Ramping-up Renewables, Energy You Can Count On.

And then following Steve's presentation, Michael Milligan, who is one of our experts here at NREL, very, very, well known in the grid integration area and he is going to be talking about some recent work, some of which was presented at the Wind Power Conference but looking at the costs and cost calization of integrating large amounts of wind into the nation's electrical system.

As the operator indicated, we do questions and answers at the end of both sessions so we'll do both presentations and then do the Q&A and we do the Q&A over the Web. So if you have questions, go up to the top. In your menu bar, there's a little Q&A thing. Drop that down and it allows you to type in your questions and then I'll moderate those questions at the end of the, end of the session.

So that everybody knows, this is recorded so the whole conference, the whole presentation are recorded as well as the Q&A and then it will be put up on the Wind Powering America Web site in about a week's time so it takes a little bit of time to go through it and put it up there. But it will be recorded and we'll let you know in the e-newsletter when that's up and available.

So without further ado, we'll introduce Steve and get to his presentation. Steve is a Director of Energy Research for the Union of Concerned Scientists, Climate & Energy Program where he conducts research on economical environment benefits impacting renewable energy technologies and policies at the state and national level. He also directs the work that Union of Concerned Scientists does on coal and natural gas and nuclear power and then on carbon reduction, emissions and water uses in the electric sector.

So anybody who has kind of followed this space certainly knows the great work that the Union of Concerned Scientists has done in this space and Steve is very prime in the middle of that.

Prior to his work at UCS, Steve was the Energy Policy Coordinator for the Wisconsin energy office for almost a decade there. Steve holds an MS in energy (unintelligible) and policy from University of Wisconsin in Madison and then has a BA in Political Science. So without further ado, can we get Steve's presentation up and Steve.

There we go.

Steve Clemmer: Great. Thanks Ian. Can everyone hear me okay?

Ian Baring-Gould: Yes, we can hear you.

Steve Clemmer: Excellent. Well thanks to NREL and Wind Powering America for inviting me to speak today. I'm really honored to be sharing the stage with Michael Milligan who is one of the nation's leading researchers on renewable energy integration issues. In fact, we drew heavily on his research in putting together and wrapping up renewable report that I'm going to talk about today.

The purpose of our report is to show that wind, solar and other renewable energy sources are already providing reliable electricity today in the United States and around the world and with the right tools and smart policies, we can significantly ramp up the (unintelligible) in the future while maintaining a reliable and affordable electricity system.

The report is also designed to answer basic questions like what happens when the wind doesn't blow and the sun doesn't shine in an accessible and non-technical way.

Wind power has been a tremendous success story in the United States. In 2000, I'm sorry, over the past five years wind power capacity in the U.S. has more than tripled. And in 2012 the wind industry broke a record by installing 13 thousand megawatts of capacity which is shown in the green bars in the chart. This represented 42% of new electric generating capacity installed in the U.S. in that year which was more than all the natural gas capacity that was installed and represented a $25 billion investment in the U.S. economy.

Cumulative wind power capacity which is shown in the blue line increased 28% in 2012 bringing the U.S. total to 60 thousand megawatts at the end of the year. This chart also showed that the federal reduction tax credit for wind has been an important driver of wind development in the United States but the

PTC has never been extended more than a couple of years at a time and in the past has led to the industry falling off a cliff when left to lapse.

The PTC is currently scheduled to expire at the end of this year. While many projects have been announced or under development, the wind industry's projecting a much lower level of development in 2013 and 2014 than we've seen in the last few years. The U.S. clearly needs to have a long term renewable energy policy to avoid this same bus cycle,

While wind only provided 3.5% of the country's electricity in 2012, several utilities state the country's already have much higher levels of wind than many people thought possible just a few years ago. This chart from our report shows that wind power provided more than 10% of the electricity produced in 9 states in 2012 with Iowa and South Dakota leading the pack with 24%. Denmark is the global leader in wind power with wind providing about 30% of the country's electricity in 2012.

Several utilities in regions have also broken wind penetration records in the past year. This chart shows installed wind capacity through 2012 for major regional transmission organizations and independent system operators in the U.S. based on information from the American Wind Energy Association and it also shows wind power's recent share of total electricity demand that was achieved on particular days in some of the regions of the country.

For example, wind power provided 13% of California's electricity in April of 2013, 25% of the mid-west's electricity in November of 2012, 30% of the south-west's power pool of electricity in December of last year, 35% of the electricity demand in Texas in April of 2013 and wind power exceeded hydrogenation in the Pacific Northwest first time ever in November of 2012. Finally, excel energy was the nation's largest utilities serving customers in 8

states and the nation's leading provider of wind power hit a record 57% in Colorado in April of 2012 and more recently hit 33% in the upper mid-west in February of 2013.

While entering large amounts of variable renewable energy into the grid poses challenges to grid operators, conventional power plants have also presented their own reliable challenges. The potential for a sudden outage at a large coal or nuclear plant means the grid operators must always have generation transmission reserved on hand to immediately replace them. And because of their size, those facilities also make the grid less flexible and more vulnerable to blackouts in the gulf line.

Just as diversifying investments strengthen the financial portfolio, adding new energy sources and technologies to the grid can fortify its portfolio improving reliability in the process. Renewable resources are less vulnerable to prolonged interruptions in fuel supplies stemming from weather, transportation problems, safety concerns, terrorist threats, embargos and the like and because they don't rely on fuels that are subject to price fights or long term price increases renewable also add price stability for consumers.

Severe weather events can also affect power plant reliability. Because renewable energy technologies are more modular than conventional power plants, the impact on the grid and the surrounding environment is usually insignificant when weather damages individual facilities.

There's also anecdotal evidence showing that wind projects have weathered recent storms better than some fossil or nuclear plants. Extreme weather events are expected to become more frequent and more severe because of climate change which will further strain our reliance on conventional generating sources.

That means that events like Hurricane Sandy which caused $80 billion in damage and widespread power outages for 80 million people all the way from Virginia to Maine will become much more common. Yet wind projects in the northeast appear to have weathered Hurricane Sandy and Irene much better than some of their fossil and nuclear counterparts.

For example, the 7.5 megawatts Jersey and Atlantic wind farm in Atlantic City took direct hits for both Sandy and Irene. During Sandy, the turbines sustained wind of 65 miles per hour with gusts that reached much higher than that. The turbines were undamaged and after being intentionally shutdown while the hurricane passed over, were generating electricity soon after.

The picture in the bottom left corner shows 6 wind projects in the northeast that survived Hurricane Irene including the project I just talked about as well as the 24 megawatt Lempster mountain wind farm in New Hampshire that's shown in the bottom right corner.

Wind turbines have also survived the recent tornadoes in Oklahoma. On May 31st of this year, just a few weeks ago, the widest tornado ever measured on Earth ripped through El Reno, Oklahoma destroying many homes and businesses in the community. That tornado had an EF5 rating which is the highest rating possible for tornados and it was only the eighth tornado with it's magnitude to be measured in the state since 1950.

Despite taking a direct hit and wind speeds up to 300 miles per hour, the two wind turbines at the Canadian Valley Technology Center, shown on the left, withstood the impact and did not (flutter) any visible damage to the turbines.

The picture at the bottom right corner showed a tornado that passed through a wind farm in southwestern Oklahoma in 2011. There's actually a very interesting YouTube video on the internet that this comes from and I would encourage people to take a look at it. It's pretty amazing.

Another example of where wind weathered the storm, so to speak, was in 2011 in Texas. In February of that year, unusually cold temperatures in Texas disabled many coal and natural gas power plants leading to rolling blackouts across the state. It also resulted in power prices at one point surged by a factor of 60 and Texas had to import electricity from Mexico. The freezing weather also shut at least 600 million cubic feet of natural gas production in three of Texas' natural gas basins. During this time, local wind power facilities kept operating and provided about 7% of electricity demand and reduced the severity of the blackouts.

Then later that year in August, Texas (experienced) a heat wave that once again caused about 20 coal and natural gas power plants to stop working. For three straight days, wind made a huge difference between keeping the lights on and the air conditioners running in rolling blackouts.

Heat and drought are already putting electricity and water supplies at risk as illustrated in the recent examples shown in this map. These electricity and water (collisions) have occurred primarily at large thermal electric coal and nuclear plants in the eastern half of the country.

These (collisions) have included not having enough water for cooling requiring power plants cut back production or even shutdown in some cases, incoming water being too warm forcing power plants to reduce their production often when it's needed the most, outgoing water being too warm which can harm or kill wildlife when power plants discharge hot water back

into rivers and other water bodies. Climate change and variability will only make these and other problems more frequent and severe in the future and wind power can actually help reduce this rift because it doesn't use any water.

Citing one more example, fossil and nuclear plants are also vulnerable to flooding from things like sea level rise, storm surge and heavy rains. But once again, the frequency and severity of these paths - impacts - are also expected to rise due to global warming.

The picture at the top left is of the flooding from the earthquake and tsunami that caused an explosion and meltdown at the Tsukishima nuclear plant in Japan in 2011. The bottom left picture shows a wind farm in Japan that was located about 300 kilometers away from the earthquake that survived and is producing power. In fact, most of the Japanese wind turbines installed in the country at that time were fully operational after the disaster and helped keep the lights on when they had to shut down, not only Tsukishima but several other nuclear plants in the country.

On the top right, shows that coastal power plants are also vulnerable to flooding from sea level rise and storm surge. Some of the options for dealing with this problem would include things like building sea walls, you know, relocating the power plant inland or they could be replaced with other alternatives over time all of which, you know, are fairly expensive options.

The bottom right is a picture that shows historic flooding that occurred on the Missouri river that shutdown the Ft. Calhoun nuclear plant in Oklahoma - Nebraska in April of 2011. My understanding is that not just due to the flooding but for other reasons, that plant is still not operational to this day but is expected to come back online soon.

These examples show that wind and other renewable sources can help maintain and even enhance grid reliability while making our electricity system less vulnerable and more resilient to the impacts of climate change. However because power outages often occur from trees falling on power lines during storms, other changes to the transmission and distribution system will be needed to make sure that wind's turbines operating after storms can actually deliver that power to consumers.

The report also describes several new approaches to operating the electricity grid that can help integrate variable renewable energy sources while lowering costs, reducing omissions, and maintaining reliability. Many of thee approaches are being evaluated at the state and regional level.

In the report, we describe eight tools that regional grid operators and utilities are implementing across the country that are highlighted on this slide. In the interest of time, I'm just going to talk about a few of these as examples.

So in a large interconnected power system the wind doesn't blow everywhere but it usually is blowing somewhere so integrating wind and solar projects over larger areas can help smooth out an uneven supply of power from individual projects. Sharing energy reserves to balance electricity in supply and demand over larger areas also greatly reduces the cost and the amount of reserves needed to support wind and solar facilities.

All grid operators use forecasting to understand how the weather will affect electricity demand. With growing reliance on wind and solar, some utilities and regional grid operators are using weather observations, metrological data, computer models and statistical analysis to project wind and solar output.

For example, Xcel Energy worked with scientists at the National Center for Atmospheric Research in Boulder to develop a high resolution forecasting system that combines real time information on wind turbines with weather prediction models to forecast the amount of wind energy that will be available 72 hours in advance.

Building on decades of atmospheric research, the system is 35% more accurate than previous forecasting tools. Because of this system, Xcel has also saved about $14 million for rate payers by reducing the output from coal and natural gas plants and by cutting wind curtailments approximately in half.

Moving towards more flexible fossil fuel power plants is also a relatively easy way to integrate more variable renewable sources into the grid. Most natural gas plants can provide this flexibility because operators can increase or decrease their outputs fairly quickly. Even wind, natural gas and other fossil fuel facilities provide reserves for short term balancing. Adding wind and solar to its system significantly reduces emissions.

Operators of hydroelectric power plants can also make a system more flexible by adjusting water flows to match fluctuations in demand and supply. The picture at the bottom is an example of a new state-of-the-art 800 megawatt natural gas power plant that came online last month near Palm Springs, California. This plant has eight units that have quick starting and (fast) ramping capability that are providing reserves to help California's growing solar and wind farms that surround the plant.

Adding large amounts of renewable energy or even conventional energy sources, for that matter, to the grid and delivering high quality wind and large scale solar from remote areas to cities will require new transmission lines. According to a (unintelligible) 19 near term transmission projects that are

under development could carry enough new wind capacity to double the current amount of capacity in the U.S.

For example, this includes a package of 17 new multi-value transmission lines that were approved by the Midwest independent system operator in 2011 in the upper Midwest that will support about 14 thousand megawatts of wind capacity and provide up to $49 billion in net economic benefits according to their analysis. Other transmission projects are moving forward in California, Texas and the Northwest, Southwest, Mountain and Plain states.

So storage is another potential option for managing variability however most large scale integration studies, many of which that Michael's been involved in, have shown that storage is not really needed or even economic for wind penetrations of up to 30% of electricity. However, storage could play an important role in the long term as renewables achieve much higher levels of penetration.

So this slide just shows a few examples of the different types of energy storage technologies. In the upper left hand corner is a (unintelligible) storage project on Lake Michigan that's owned by consumers and energy. The bottom end is a (unintelligible) solar project that BrightSource Energy developed that uses thermal storage using molten salt. The company is also building a 370 solar megawatt facility in California's Mojave Desert right now that's using mirrors to focus the power of the sun on solar receivers to top power towers.

In the upper right hand corner, a company called A123 that has a 2 megawatt battery storage unit that's being used to provide ancillary services to grid and the bottom right hand corner shows a schematic of a wind compressed area and storage project from a company called General Compression that is interested in developing those projects.

With these tools in hand, we can wrap up renewable energy to much higher levels. Leading countries have set strong targets for renewable energy to realize its future. The United States, unfortunately, does not have a national target nor a long term policy to extend the use of renewable energy however 29 states and the District of Columbia have adopted renewable electricity standards which require utilities to supply a growing share of power from renewable sources.

Out of these states, 17 require that at least 20% of the electricity come from renewables by 2025. In addition to this, at least 18 countries have developed binding renewable electricity standards. Three examples of this, some of the leading countries like Denmark whose goal to produce 50% of its electricity from wind by 2025, 100% of its electricity from renewable energy by 2050.

Germany also has a binding target to produce 35% of its electricity from renewable by 2020 with the target rising to 80% by 2050. Even China has a near term target of producing 100 thousand megawatts from wind and is considering doubling its solar target to 40 thousand megawatts by 2015.

Numerous studies have shown that we can transition to a low carbine electricity system based on even larger levels of renewable energy over the next four decades given the right policies and infrastructure.

For example, this slide shows some of the results from a ground breaking 2012 study that NREL led that found that renewable energy technologies available today could supply 80% of the U.S. electricity in 2050 while meeting demand in every hour of the year and in every region of the country. As shown in the chart, under this scenario, wind and solar facilities provide

nearly half of U.S. electricity by 2050. This scenario would also reduce power plant carbon emissions and water use by 80%.

So finally, to conclude, the study, studies by NREL like the one I just showed and other ones by MIT have shown that a more flexible smarter grid can overcome the challenges to integrating renewable however these changes alone are not enough to achieve a meaningful transition to renewable electricity.

Strong state and national policies are also needed to overcome market barriers to developing clean energy and the supporting technologies for integrating them into the grid as well as more fully recognizing that the economic and environmental benefits of transiting away from fossil fuels. Policy support is also essential to ensure the continued growth of the renewable energy industry and the cost reductions that come from learning, innovation and economies of scale.

So some of the policies that could help achieve this would be to expand on the success of the states that have renewable electricity standards and adopt a strong national standard that leaves 25% by 2025 which could help accelerate this transition. Targeted tax concerns and more funding for research and development are also important for lowering the cost of emerging technologies as well as to help develop the integration technologies as well. Strong pollution control standards for coal power plants are also essential to protect public health and the environment.

Finally, a national commitment to renewable energy will deliver deep cuts in carbon and others (unintelligible) trapping emissions quickly and efficiently enabling us to avoid the worst impacts of climate change. We have the tools to significantly wrap up renewable energy use and keep the lights on. With

ingenuity, innovation, and smart policies, we can fully transition to a clean renewable electricity system.

Thanks again for inviting me to speak at this webinar. Now I'll pass it over to Michael.

Ian Baring-Gould: Great. Thank you so much Steve. We've got a bunch of questions. We'll hold those until after Michael's presentation because, I believe, Michael could very well address some of the questions that we have there.

So without further ado, Michael Milligan who's a principle researcher here at The National Renewable Energy Laboratory who is going to talk about (green integration) costs and some of these other factors.

Michael has been here at the Wind and Energy Program since 1992, so 20 years working in this area plus years before that and as Steve indicated, he is one of the world experts in this area as his bio really indicates.

Michael has published over 140 technical reports, articles, or book chapters. He participates on the leadership team for the North American Electrical Liability Corporation Variable Generation Task Force. He's the coacher, the probabilistic methods working group, the variable generation sub-committee of the Western Electric Coordinating Council. He sits on the International Energy Agency Task Force 25 which is the development of power systems with large amounts of wind energy. He served on probably more technical review committees than anyone can imagine and is currently on a wind energy task force with the Western Governors Association clean and diverse energy project.

So as we can tell, Michael comes to us with vast experience as well as a wonderful person to work with. So, without further ado, Michael.

Michael Milligan: Great. Thank you very much Ian. Can you hear me okay?

Ian Baring-Gould: Yes, we can hear you just fine.

Michael Milligan: Great. Okay. Well, thank you. I appreciate the invitation to talk to you all. The issue that I want to talk about is related to wind integration costs. And we've done some work on this and for those of you that need a cure for your insomnia, here's a leveling and as Ian said, this will be posted later on so you can look at that at your leisure but I want to acknowledge several co-authors here from NREL - and (Charleston Clarkson) (unintelligible) and (Ken Lim) from U.S. (unintelligible) that helped put this all together.

And it's, I'm going to cut through the headlines here and then you can all, you know, not pay attention if you like. I don't have as many cool pictures as Steve has. That was a great job.

But integration costs for wind or for actually for any other technology turn out to be surprisingly difficult to calculate correctly. I have a corollary to that statement which says wind integration costs are extremely easy to calculate. Wrong. So we'll talk about that in a little bit, what that means.

The other thing that we've looked at is other forms of generation also imposed in integration costs so it isn't just wind. I'll give you some examples about that a little bit later on. And so all of this together sort of leads us to this question of well, you know, if we're going to worry about integration costs, perhaps the right way to worry about it is to worry about it on a performance basis not just on well you're wind and so you have an integration cost.

.

Ian Baring-Gould: Michael, we're having a few people say that you're hard to hear. Could you move a little closer to the phone?

Michael Milligan: Is this a little better?

Ian Baring-Gould: Try a little bit more.

Michael Milligan: A bit more? How's that?

Ian Baring-Gould: I think - try that. Thank you.

Michael Milligan: Okay, great. Sorry about that. So what do we mean by integration costs? Well we take a look at how the power system is already designed and operated and this graph gives you a sense of kind of the typical day in the life of a power system operator.

The graph, at the top, shows 24 hours. The curve is showing the system loader or demand for electricity and what we see here is, a surprise to most of us, but in the middle of the night you can see that the demand is pretty low. During the morning it ramps up, reaches a peak, sometimes in the middle of the day and then it depends on the system and whether it's summer or winter and so forth. This particular graph is from a winter because you can see a secondary peak and then the load comes down.

And for decades we've been designing the power system to manage this variability and this graph is sort of a hypothetical one. It's actually based on real data but what is shows is that during the middle of the day, the demand for electricity can be substantially higher than it is at night.

I warn you that the scale of this graph is a little bit off. It looks like daytime demand is 10 times higher but it's probably more like doubly, double what it would be at night. We also have other time scales that we worry about in system operation and so if you take a look at the, well 4:00 in the morning over here, you can see we have a little blowout bubble.

It's a little hard to read this, at least on my screen but what's happening in the timeframe of seconds to minutes, is that the demand for electricity can change. It can go up a little bit if somebody turns on a fan or other electric mode or lights or something like that. Those devices get switched on and off, of course, all the time. And if you have a broad region, as Steve pointed out, that variability tends to decline on a per unit basis.

But we have certain types of generators that we more or less assign the problem of keeping the system balance, seconds to minutes, and we call that regulation. You can see at around 9:00, 10:00 in the morning this, or the ramp-up of the load actually extends for several hours. And we call this load following. It's over a longer time period from maybe tens of minutes to an hour, maybe multiple hours. And you can see in the graphs here that in the morning the load picks up quite a lot and we have operating procedures so that system operator has a load forecast.

I know that it's going to be happening with a certain degree, some uncertainty but I have a pretty good idea. And so we can manage the variability of the load by itself pretty well. We know how to do that.

Well what happens if you put a lot of wind into the system and this next graph gives us kind of a nice appreciation for what happens. If you look at the top panel of the graph, you can see the electricity demand and this is one week of data so you can see essentially seven bi-loadals or peaks here, so one per day.

So the black is the electricity demand. The wind you can't see directly but essentially what we're going to do is take the black, which is the demand. We subtract off the wind power. This is a very high wind penetration rate, in this example. And what we're left with is called the net load and you see that in blue. So think of the blue as the loads that have to be served by the conventional generators after we've already served all the - sorry - after we've already counted for all the wind energy.

And we can use this to get a lot of insights as to what happens. For example, in hours, maybe from 10 to 20 over here on the left-hand side, you can see there's a pretty sharp increase in the net load. And what that means is, we can take a look at the demand itself is relatively flat during that period. But the wind has fallen off and so what that means is that as the wind falls off we have to turn up or ramp up other generators so that we can maintain system balance.

And you can see a couple of examples where the blue is quite steep. One here about a third of the way to the left and then one here toward the right hand side and what that says is we've got a lot of wind at sort of the notch at the bottom of the blue. The wind dies off and so as the wind dies off, we have the increased generation from our conventional units.

And so clearly there's a lot more variability in the net load, the load that needs to be managed, And so when we take a look at or think about integration costs, people generally accept the premise, probably everybody accepts the premise, that if I add wind power to my system, it's going to increase the variability of that I have to deal with and it's also going to increase the level of uncertainty that I have to deal with.

I don't know exactly what the wind is going to be doing one hour from now or six hours from now or tomorrow. And so I have to, I have to plan my operation in such as way that I have sufficient reserves so as the wind does something different than I think it's going to do a day ahead or an hour ahead, I have other flexible generation that is available to help me keep the system balanced.

So when you think about integration costs, we're really trying to capture the cost of the variability and the uncertainty that we get from wind. And solar's going to be similar. There's a little difference in the behavior of solar but we won't worry about that too much in this presentation.

So when you say well what are the, what are the costs of variability and uncertainty? The cycling efficiency of the thermal plants tends to be a cost of variability so if I have a, for example, a coal plant and I reduce it's output, that coal plant might be operating at a less efficient point on its heat rate curve and others, it takes more BTU's of coal per megawatt hour when it's partly loaded compared to when it's fully loaded. And so that's a bit of a cost.

And we also need some additional reserve. At NREL we call these flexibility reserves which are generation or could be demand or sponsored, could be storage, whatever's cost effective that allows me to increase or decrease the net output of my generation suite or the (unintelligible).

And it turns out that integration costs are really not unique to wind or solar. But before we dive into that I want to talk a little bit about how integration costs have been calculated in the past. There have been a number of studies standing 10 to 12 years where people have attempted to calculate integration costs and I think the, our ability to do that has increased quite a lot but the difficulty is that I have to compare a simulation of the power system that

includes wind energy with a simulation of the power system that does not include wind energy.

That in itself isn't terribly difficult. What's difficult is to figure out what the base case is. What do you do in the case where you say I'm not going to include the wind so that I look at sort of the base, a base case? And one thing that's been done by some of the early integration studies, many of them actually in the past, was to take an energy equivalent generator to the wind, so maybe your wind, say just for an example you've got 1000 megawatts of (unintelligible) wind. You want to take a look at the integration costs.

So you do the modeling run with that wind as delivered so it's going to have all that variability and uncertainty in it. And then you do a second simulation where you say well, the average output of that wind plant on Tuesday was 400 megawatts. And so you do a simulation where you say I'm going to remove all of the variability and all of the uncertainty from this wind and deliver it as it we could deliver it as a flat block of energy.

And it turns out that that approach, while appealing in some ways does cause some unintended consequences because it distorts the value of the wind energy and puts that into the cost. So, you know, how do we measure integration costs? How should it be done? How do you untangle the cost and the value and this problem becomes complicated for a couple of reasons.

The power system is extremely non-linear and that means it's very difficult to separate costs. We can't directly observe integration costs. If you went to lunch today and got a burrito, it's pretty easy to observe the cost of that burrito. You know, the $5 or $10, whatever you paid, it's directly observable and we can calculate it. It's trivial to calculate.

But if you say well now I'm putting a bunch of wind on my power system. What is the cost that variability and uncertainty gives me? That's not directly observable and my statement is easy to prove because if you look at the dozens of integration cost studies that have been done over the last decade, you'll find that many of them will come up with a new method. So where the old method doesn't work, I'm going to try this new method. And so we have many, many different methods that are used to calculate the integration cost.

Why? Because it isn't observable. And people have thought long and hard about the problem and it's a difficult one to solve. And that's what leads us to this question - are there integration costs of other types of generations and that turns out to be a pretty interesting thing. I'm going to skip through some of the points in this slide because I'm going to be a little short on time but we can easily calculate total system costs with a power system simulation.

But those costs, the operating costs and capital costs depend tremendously on many other factors. For example, if I'm putting a bunch of wind onto my system what's next in conventional generation?

Now we're seeing a large number of coal plants retiring over the next, you know, several years and the total cost to operate the system will clearly change. We don't know exactly how because that's going to depend on things like the price of natural gas.

Cost of the system depends also on your transmission network, how big is the build out, if any. What are the institutional constraints, market constraints or other delivery constraints? What are the constraints from neighboring systems who exchange energy? Those are important aspects. Do the existing markets or lack of markets, do they allow access to the physical capability that's in the ground.

We did some work, seven or eight years ago, my partner in crime (Brendon Kirby), and we actually looked at several balancing areas and we said let's calculate the ramping capability, the flexible capability that we know physically exists by taking a look at actual generator data and then compare that to what the system operator had access to.

And there were two different answers. So sometimes there's a lot of physical capability that's in the ground that cannot be accessed as a result of institutional market rules or operating practice.

So I like to talk about a term I like to call BFO which is a brilliant flash of the obvious. And this slide has that. You know, if you talk about cost causation, what we're trying to identify is a particular thing. It could be a technology in the power system and the cost that it causes on the system and the BFO of all that is if you take the causer away, the cost also goes away.

And I know that sounds pretty obvious. We've actually seen integration cost studies where you put in the wind and you do all these calculations and then you take the wind out and some of the integration costs are made even though the wind plant's gone. So, and again, I think that's an artifact of the difficulty, the impossibility really of observing integration costs in the first place.

So let's look at this question of whether there are other sources of integration costs on the power system. It turns out there are. We've done some work, this is a bit of an i-charge here, this graph that you see in the upper right hand corner, we did some work looking at the energy and balance market but more specifically we looked at large wind exports coming out of the Bonneville Power Administration balancing area.

And it turns out that roughly, 80% of the wind energy in BPA is exported outside of the region. It also turns out that those export are handled on an hourly block basis. So what does that mean? It means that, for example, if the wind was forecast to be at 3 thousand megawatts the next hour and the wind drops to 1 thousand megawatt during the course of the hour, then Bonneville is on the hook for supplying that 2 thousand megawatts that had disappeared.

Then at the top of the next hour, Bonneville and the off-taker of the energy, it might be California or others, have to totally switch their units. Bonneville would ramp down while California ramps up as they hand off this large block of energy and it turns out, we calculated that Bonneville's reserves could be reduced by roughly 80% if they went with 10 minutes hand off with the exporter, essentially.

Contingency reserve is another source of integration costs and I'll show you an example of that in a moment. Contingency reserve is the extra generation that must be online in case another generator or a large transmission line fails. Every power system has a set of rules governing contingency reserves and those reserves are absolute. They must always be available. In the case that you do have a unit that trips offline there are rules that govern, you know, how long does it take before you've restored the reserves so that if you lose another you're still okay and you can keep the system going.

New low cost base load generation can actually cause an integration cost and this is pretty surprising to a lot of people. I'll walk you through that one in a moment. And it also may be the case that a conventional generator's thermal unit, for example, they don't follow a generation signal so we'll also take a look at that one.

But what about contingency reserves? The rules for how this works will vary to some extent but usually in a reserve sharing group, a group of utilities that share this type of reserve, the level of contingency reserve is based on the largest generator in that reserve sharing group.

So if you've got a 1 thousand megawatt nuclear unit, then that would probably set the contingency reserve for that area. There may be some additional contingency reserves. For the sake of argument, that's a good way to do it. If a new unit is built in the region, you know, if a new unit is larger than the old one, then everybody's contingency reserve will go up.

So let's take another example. Suppose that I'm in a reserve sharing group and we have a 300 megawatt unit which is the largest unit in the group. Well if there are two utilities and they're sharing equally in the contingency reserve, then each of them have to supply 150 megawatts of contingency reserve.

Now utility number 1 decides I think I'm going to go out and build myself a big coal unit, just as an example. People aren't building much coal these days. But, so this new coal unit comes in. It's a 500 megawatt unit. Utility number 1 built that unit. Contingency reserve has now gone from 300 to 500 megawatts.

So I'm utility number 2. I was sitting here minding my own business and next day I wake up and I find out that the contingency reserve for the system's gone from 300 to 500 and I have to supply not only the original 150 but an additional 100 megawatts. I didn't do anything.

So we have the, sort of the principle of cost causation which says cost causers - hey in this case utility number 1 caused utility number 2 to increase contingency reserves and so we don't really have a cost causation, (unintelligible) or now.

I don't want to spend a lot of time on this graph but this particular graph taken from our paper shows that there are a number of different ways that you could allocate contingency reserves based at least in part on the size of the unit, possibly based on how often the largest contingency, the largest unit, does fail, perhaps even allocating across multiple units. But that's not done in the United States.

What about conventional units? This series of two graphs that you see come from two actual units in the Midwest. Now it turns out these happen to be coal units but they could have been anything else, a gas unit or some other thermal unit.

Both of these units were selling regulation. Regulation is a service that the Midwest independent system operator - sorry to (bid punted) the independent system operator changed their name. They buy regulations from generators. So the generator will bid in and they'll say, you know, I can supply a certain amount of energy. I can supply a certain amount of regulation. And (Liza) runs the big computer programs that optimize the power system and say, okay, I'm going to pick this collection of five or six units to provide regulation and other units to provide energy.

So the two units in this graph have both gone through that optimization process and (Liza) would have said, yes, I want to buy regulation from both of you.

So if you take a look at the top panel, this is the unit that responds pretty well.The AGC signal, the automatic generation control signal, is fed to the unit. It's calculated by computer and that's the dotted green line that you see. And the solid red line represents the unit's actual performance. And this is

actually pretty good. You don't expect perfect performance. You've got a lot of thermal inertia in the power plant and so you give it a signal to increase or decrease output. It's going to take a little while before it can respond but this is actually pretty good.

And this unit, you know, you would argue is doing a good job of providing regulation and therefore should get paid appropriately. The second unit, however, is still getting paid for providing regulation but you can see it doesn't do a very good job of following the control signal. So 30 minutes into the hour, you can see that the control signal is telling the unit to come down to 410 megawatts and the unit keeps going up. The control signal tells it to keep going down and eventually the unit does respond.

But in this particular example, this coal unit imposes a 31 megawatt regulation burden on the power system. Now I'm not going to claim that all coal units do this. Some do particularly older units. Some of the older gas units do this as well. And so what this does point out, however, is that some units can actually provide some of the ancillary services and other thermal units cannot. Not only do they not provide them, they actually consume ancillary services. So that's kind of an interesting example. We've seen the same thing with gas plants in California and other places.

Now this maybe surprises a lot of people. Wind turbine technologies changed tremendously and I think will continue to change to some extent in the future. We now have wind turbines that can respond to a regulation signal. Though an individual turbine can respond and if I now have a wind plant of, you know, hundreds or maybe 1000 megawatts of wind, I can optimize the performance of that plant to also provide a regulation signal.

I won't drag you through the gory details of this plot here but the green line which is kind of up and down, is what we call the area of control (error), and that's what the system operator is trying to maintain. This isn't particularly bad. It looks worse than it is.

But if you take a look at the wind AGC schedule, it's called here, which is sort of the purple, what you'll see is that the wind, or if you could see my mouse cursor here, but just a little ways in here you can see the wind AGC is going down at the time that (Ace) is high and that's exactly what you want it to do. You want to try to bring (Ace) to zero and the way that the wind could do that is by moving down a little bit.

So all of a sudden, you know, we sort of set the world upside down. We said, you know, there are some thermal units that might be consuming regulation and some wind plants that actually may be providing it which is the sort of counter to the conventional wisdom that all wind plants are going to impose integration costs.

I'm getting short on time so I'll kind of go through this in a little bit.quickly. Up at the top we have a very simplistic hypothetical power system that has coal in black or gray. We have natural gas (run cycle) in dark blue and (unintelligible) units in kind of an aqua color.

The middle panel shows what happens if you add wind to this hypothetical system and what you see is the blue combined cycle plants are now moving around a little bit more. They're cycling more. You can see the coal plants are moving down a little bit and that's the kind of picture that people say yes, there's an integration cost because those coal plants and those gas plants are moving around and they're running less efficiency.

The bottom graph does away with all the wind, especially starts with the top graph and says let's add a new technology and this is coincidentally pink. It doesn't necessarily have to be nuclear. But you get a bunch of nuclear generation that's got a very low variable cost. Might be a high capital cost. Comes in and it causes the coal plants to cycle. This is exactly what happens in Ontario.

I remember a number of years ago they did running their coal plants as (nuclear) units. They brought in a bunch of nuclear units so the coal plants started to cycle. They actually refurbished a number of those coal plants so they have a lot more flexibility then most any gas plant. I'll say that again.

They refurbished the coal plants in Ontario so that they have more flexibility than most gas plants have. Those coal plants are scheduled to come offline more or less permanently a little bit later this year.

So that kind of alludes to this idea, you know, if we're going to assess integration costs, maybe it should be calculated based on the performance of the unit. We should be technology neutral. I don't care if it's a coal or a gas or a wind or solar unit. If I'm going to impose an integration cost, I want to take a look at the performance of the plant and see what it's doing.

If it's a wind plant that's providing regulation, it makes no sense to say well I'm going to have to procure extra regulation for the wind plant. No, the wind plant is actually providing it although a lot of wind plants do that. And then there are actually some market reforms that need to happen before we'd see a lot of that happening.

So wrapping up, pretty easy to calculate integration costs incorrectly. Pretty hard to calculate them correctly. Other technologies can also impose

integration costs and I think I just mentioned this, it might make more sense from a generator performance standpoint than from a, you know, what kind of technology are you standpoint.

So with that, we'll turn it back over to Ian.

Ian Baring-Gould: Great. Thanks Michael. We're almost to the top of the hour and we've got a bunch of questions so hopefully we'll be able to rely on our two speakers to hang out for a little bit and all of those that can stay, please do so.

The first question comes from (Roger Plantain) and this can probably go out to both of you. He's interested in regulations governing private producers in grid connection. Is there a good resource that combines the information for the 48 states?

Man: That's a hard question. Could you repeat part of that, Ian?

Ian Baring-Gould: Basically, a document or a reference site for regulations regarding private power producers and grid interconnection.

Man: I think from (FERC) or something like that.

Michael Milligan: I'm not aware of a one site fits all. There's a limit. I think it's 20 megawatts but if you're smaller than that you qualify as a small generator. Otherwise you qualify as a large generator and that does up the ante a little bit in terms of the type of setting that has to be done before you interconnect. It also depends if you're interconnecting on the transmission system which is, you know, generally a little more difficult and more expensive but on the other hand you can connect at a higher voltage. And that's more efficient if you've got a larger

plant but I'm afraid beyond that, the questions a little bit out of the domain that I'm really familiar with.

Ian Baring-Gould: Steve, do you have anyplace that they might go?

Steve Clemmer: No not really. Not beyond what Michael is saying about, you know, the cutoff between larger generators versus smaller generators and now there's a proceeding going on at (FERC) right now for the small generator interconnection that's underway. They're in the middle of that still. Congress was due a few weeks ago on that so beyond that I'm not sure.

Ian Baring-Gould: Okay, great. Got a number of questions, well actually before you get to those another question on storage. From (Alexander Crenia), I believe I'm pronouncing that right, to Steve, why did you not discuss the higher emissions from gas plants used for renewable backup.

Steve Clemmer: Well it's, I guess it's true that reserves that are used for integrating wind and other variable renewables would generate some emissions but wind and renewable energy typically will displace coal and natural gas generation that's on the (unintelligible) whenever it's operating. So the additional gas generation that's needed to provide reserves is really pretty small compared to the displaced generation.

So what I've typically seen from the studies that have been done on this is a new reduction in emissions of 95% or more, roughly speaking, from renewables. So the reserves do offset some of the emission reductions but the emission reductions are still very significant.

Michael Milligan: And if I could add, I agree completely with what Steve said. We are about to release the Western Wind and Solar Integration Study Page 2 which looks at

penetrations of up to 33% combined wind and solar in the western interconnections. We developed some very, very detailed plant specific models based on the continuous emissions monitoring system that the EPA runs. Every thermal power plant in the U.S. has to provide information on it's emissions, every hour that it operates. So we got that data for every plant in the west, gas, coal, you name it and we put that into our modeling and we calculated the emission reduction with wind and solar.

As Steve said, you get, and I can 't recall the exact number, we got somewhere around 30%, don't quote me exactly, reduction on most emissions. But, in fact, there is a little bit of it hit on efficiency that you take but if you reduce emissions by, you know, round numbers, 30% you might give back one of those percents to inefficiencies of the reserves but it's a net of large benefit.

Ian Baring-Gould: Great. And thank you. And do you know when that report is coming out, Michael?

Michael Milligan: Soon.

Ian Baring-Gould: Okay.

Michael Milligan: It's in the final stages. So I would think the next month or so.

Ian Baring-Gould: Okay. And then this is an initiative that's come up repeatedly. Do either of you, can you point to kind of studies or other published materials that talk about this impact?

Michael Milligan: There's about, our study will address it in probably more detail than almost any other study I'm aware of. But I know there's been a lot of misinformation about this issue which says well, you know, if you're taking a thermal power

plant and you're running it at a less efficient point on it's (heat rate) curve, then therefore the marginal emission rate is going up so the emissions per megawatt hour, but as Steve said, we're de-committing and we're running a lot less energy through these units if we've got a lot of wind or solar on the system.

So total emissions fall even though you might have some plants that might be producing a little bit more emission whether it's carbon or whatever you're looking at per megawatt hour but they're producing fewer megawatt hours and therefore fewer emissions.

Ian Baring-Gould: Great. A question for both of you. Please explain why storage and balancing is not reduced until -- sorry, storage and balancing is not needed until penetrations exceed about 30% and then a kind of a follow-on question is (Kenneth Lutz) has not seen any studies whenever people talk about the need or not need for storage they say that's because you have natural gas to balance.

Have there been any studies that actually compare storage to natural gas and at what point storage, other terms of storage is actually a more cost-effective solution than natural gas plants to provide this balancing.

Steve Clemmer: I think Michael is more of an expert on this topic than I am but I would just quickly say that I think the first question was in response to something I said in my talk which the study that I referred to that Michael's actually been involved in said that storage wasn't needed until wind penetration exceeds 30% or it was too expensive.

I don't believe they said that balancing was not needed. Balancing definitely is needed at much lower levels than that it's just a question of what do you

provide the balancing with. Natural gas plants, hydro, other things like that are lower cost than building storage I think is what they pretty much show.

So I don't know, Michael, maybe you could comment more on -- I know the eastern and western grid integration studies looked at the included storage as did the 80% by 2050 NREL study.

Michael Milligan: Yes, it's interesting. We've done some work on storage, not a huge amount. Sometimes people think that I'm anti-storage which is absolutely not true. I love storage.

I think the issue comes down to what's the most cost effective way of balancing the system. People - it's kind of natural I think - to think well, to get a lot of wind energy in the system I'm going to have to go get a bunch of storage whether it could be battery, it could be pump storage hydro. It doesn't what it is, some form of storage.

That certainly does help and we have around 300 megawatts of pump storage here in Colorado and it does help Public Service in Colorado to sell energy in balancing.

If you think about other types of power plants, take natural gas is a good example. Natural gas plants have their own storage, it's fuel storage.

You can store the fuel of the gas plant until you need it and burn it when you need it. It turns out that the storage technologies today are not very cost competitive with other approaches.

In the western wind and solar integrations phase one, we did look at this, not exhaustively but we said let's take all the pump storage that we have in the western U.S. and let's double it.

We got into the production model and added a bunch of fictitious pump storage plants. The model - which is a least-cost dispatching commitment model - so it relentlessly pursues the least-cost solution of maintaining system balance.

The production simulation came back and said you're not going to use the pump storage all that much more. Even though you doubled it, I'll use a little bit more but not that much, and we said, yes you will. We forced the model to use the extra pump storage and it turns out that production costs went up.

The storage also is complicated by the fact that I have to fill the storage so that it is available when I need it. I need to drain the storage when it's economic to do so.

It turns out that to effectively run a storage device when you have a lot of wind means that the storage operator - maybe the system operator - has to have some pretty good knowledge of the future. What's the wind forecast? What's the load forecast?

Now that's not necessarily impossible but it turns out that dealing with storage is harder than we thought. There are other more cost-effective ways of balancing the system.

It may be that I take an efficiency hit on my gas plants or my coal plants or whatever but those efficiency hits are less expensive than going out and building a bunch of new storage.

Now the renewable energy future study that I think Steve was referring to, we had 80% of electricity coming from renewable technologies. Roughly 50% was coming from wind and solar, then the remaining 30 was coming from biomass, and geothermal which, from an integration point of view are a little easier to think about.

When you start getting very, very large quantities of wind and solar you have a choice of either curtailing some of that wind or solar during periods of low load and high wind for example or storage could be potentially effective in helping manage that variability.

At this point we don't see it as a widespread cost effective solution but in the future they will be an efficient and cost effective solution.

Ian Baring-Gould: Great. A follow-on question, looking at hydrogen production and to a degree whether the same question arises looking at storage but hydrogen or other uses for excess electricity. Have studies been done to look at that and what are the results of those studies?

Michael Milligan: I'm not aware - Steve may be - I'm not aware of any large studies. I know there have been some small sort of pilot studies that look at that but as far as looking at how that would affect the transmission system on a large scale I'm not aware of anything.

Steve Clemmer: Yes, in our wrapping up renewables report we do list hydrogen as a potential storage option and there's a couple of references listed there but as Michael was saying, we weren't able to find very man and the ones we do reference I think are from 2003 so I'm not sure what new information is available on that topic.

Ian Baring-Gould: Great, thank you. From (Dwight Bailey) to you, Michael. What are some examples of institutional costs as you reference in your presentation?

Michael Milligan: I guess some of the examples might be, for example, the western interconnection with the U.S. we have somewhere on the order of 37 or 38 balancing areas.

I get in trouble sometimes with some of these. I don't recommend that they merge or anything like that but the point is that the institutional structure that we have does make it difficult to balance the system if you have a lot of wind and solar.

We have a small piece of the western wind and solar phase one report that talks about considering Wyoming. We take a look at the variability that you would get if you introduced this large wind penetration in Wyoming and it turned out that it made Wyoming look like an enormous wind plant that happened to have a little bit of electricity demand.

It's literally impossible to balance that unless you have coordinated power system operation. That's one example. It kind of goes back to Steve's comment earlier.

Over larger areas the pre-unit variability of wind declines but the other thing that happens is if you start combining or coordinating operations for multiple balancing areas you find that your ramping capability - by combining two areas - the ramping capability goes up linearly.

So area A can ramp up at 200 megawatts an hour or three and 400 megawatts an hour. Those add up whereas the need for ramping adds less than linearly so you can do more with less kind of. So that's one example.

Another example is faster economic dispatch for the power system is really efficient because it minimizes the somewhat arbitrary control that goes into the regulating plants.

Regulating plants are wonderful. I love them, we always need them but regulation is a sort of quasi-economic product. You buy it in chunks but you operate it in such a way that you're not really, you don't really care which is the economic unit.

Economic dispatch is just the opposite. You care very much which is the most economic unit. So moving to these shorter time steps and 60% or 70% of all the electricity markets in the U.S. do run at five-minute economic dispatch. Most of the west runs at hourly dispatch and scheduling.

Now having said that, FIRC, the Federal Industry Regulatory Commission recently came out with Order 764, which mandates interchange to go to 15-minute time steps instead of hourly time steps.

There's going to be some infrastructure that has to change - computers and communications and stuff like that - but I know that the eastern interconnection, the markets are moving on a 15-minute coordination and also in the west.

So those are examples. I think the sumo wrestler theory of efficient integration - if you're big and you're fast, big meaning large balancing areas, fast meaning

fast economic dispatch - you get tremendous increases in the capability of integrating wind and solar.

Ian Baring-Gould: Great. Thank you Michael. A question about whether the slides are going to be posted online. The slides themselves are not posted explicitly just because of the work that it requires to actually get slides compliant with all the federal regulations.

The webinar itself is posted so you can view the webinar but the slides themselves are not and I would encourage you to contact either of the speakers and I'm sure they'd be more than happy to provide slides to anybody who wants to.

A quick question from (David Kerlick). When we're talking about the figure of 30% which is often given, is that nameplate capacity or actual measured output generation?

Michael Milligan: Are you talking about 30% penetration?

Ian Baring-Gould: Typically, when a term is used - and it varies depending on where you are and what service provider and all that kind of stuff, 30% or 20% - but when people say storage is not needed until we get above 30% penetration for Xcel service territory. Is that typically a capacity number or a power generation number?

Steve Clemmer: When I was referring to that number that was based on the eastern and western greater interconnection studies - I'm sorry integration studies - which I believe was based on generation as opposed to capacity. Isn't that right, Michael?

Michael Milligan: That's right. Annual energy so 30% means that 30% of the energy for the year is provided by wind or wind and solar, whatever it is. Yes.

Steve Clemmer: The 30% generation is important but the other important point is those studies were done for essentially the entire eastern half of the country and the entire western half of the country as opposed to a specific utility system.

Michael Milligan: That's also a good question to ask because some of the earlier integration studies took a look at the ratio of installed with capacity to the peak load of the system. So you do get a -- typically that's a higher percentage than if you take a look at the annual energy.

If you're reading a report it's always good to look for the definition. Are we talking about annual energy or peak.

Ian Baring-Gould: Great. Let's see. I know Michael has published reports on wind diversity. Does he believe there's a way to put a value on wind farms, put in lower power -- sorry, lower quality wind sites whose power output does not correlate with the higher capacity sites and can be used as a way to smooth out the ramping of the higher quality sites?

Michael Milligan: That's a really good question. Right now the way wind plants have been - the financing and acquisition of wind - has really been based on energy only.

If I'm a wind developer I'm going to get paid based on the number of megawatt hours I'm going to find a place to plant the turbines where I'm going to get the most energy possible and I really don't care about smoothing the output because that's not my responsibility.

I'm not getting paid nor am I getting necessarily penalized for that. I think the question is how to value variability is kind of the flip side of valued flexibility.

Right now in most of the world that I'm familiar with, we don't do a very good job of valuing flexibility and therefore we wouldn't do a very good job of putting a value on saying I'm going to go to a slightly lower quality wind area and put in wind turbines and combined with some other wind plant we get less volatility.

I think there's a lot of interest in trying to figure that out, not just in this example of putting turbines in lower quality areas but flexibility turns out to be a really crucial thing that you need when you have lots of wind and solar.

I know different RTOs around the country - I think I could say this - every RTO in the country is looking at some sort of flexibility product or at least thinking about flexibility product, which would implicitly put a dollar on flexibility on the power system.

Now if that happens it may be that I could then - as a wind plant developer - come in with a lower energy producing site and then I could say, look, you're paying a certain amount for a certain flexibility and implicitly I can provide that so what's that worth in the contract.

I'll charge you the energy price, we'll negotiate that, but I also get a price for what I can provide. That hasn't happened yet. Same thing is true for wind plants that can provide regulation.

That capability exists today but I'm not aware of it. I'm aware of a few cases where that's being used but I'm not aware of cases where the purchase

agreement between the wind plant and the off-taker has included provisions for regulating service.

Ian Baring-Gould: Great. Thank you. Then one last question to both of you from (William Irvin). This is specifically in relation to California although I'm going to generalize the question a little bit.

In California a lot of electricity is used to pump water around. In principal with our reservoirs in the system, one could use those when the pumping is done for balancing and regulation and things of that nature.

Can the flexibility be used to balance power grids and so taking this a step further we're talking about big loads in California being water pumping, but you could expand that generally.

I mean currently Xcel right now turns off your air conditioner when they're having peak power issues. How much and what reports do either of you know to really look at the flexibility on the demand side as compared to the supply side to allow increased use of renewables on the grid.

Michael Milligan: That's a great question and I think water pumping is certainly a subset of demand response. I know that that issue is gaining a lot of attention. Some of my colleagues here at NREL recently did publish a report - Paul Denhollm and some others - looked at that.

You can find that on the NREL publication web site, nrel.gov/publications and then search for Denhollm. I can't remember what year, maybe in 2011 or '12.

That report talks about some of the principals around demand response. I don't recall a lot of discussion on water pumping per se but again I think that's an issue that a lot of folks are interested in.

Part of the value demand response gets back to how do you value flexibility. What do I need to operate the power system, what do I need the demand response to do and how do I pay for that and how do I know that the demand response has done what I asked it to do. A lot of good questions there.

Steve Clemmer: Yes, we definitely talk about that issue as well in the report about managing customer demand, demand response programs. I haven't looked specifically at the issue that he's asking related to California.

I do know that in the ISOs in New England, New York and the mid-Atlantic they're actually allowing demand response programs to bid into the systems to meet future electricity needs if they're less costly than generating the electricity.

There's been some pretty good responses to some of those requests and those bids that you can actually access online if you want to look at them.

Michael Milligan: Actually as Steve was saying that I was reminded of the fact that in Texas, ERCT, the Electric Reliability Council of Texas, the market operator there allows for half of the contingency reserve to come from demand response.

If you recall - I think it was 2008 - there was a very highly publicized wind event where the wind forecast for the day was based on yesterday's forecast, which isn't a particular good way to do it, but ERCT was actually testing their wind forecasting technology.

The forecast was in sort of beta testing. What happened was there was this sort of perfect storm literally a storm which came in with high winds, brought low temperatures so people started turning on their heaters in their houses.

The wind plants, many of them reached overspeed and starting cutting out. At the same time a conventional generator tripped offline, so three bad things happening all at one time.

What ERCT did was they deployed that demand response as part of their contingency reserve. It was widely reported that there was massive load shedding which is a different thing.

ERCT I think is ahead of most folks of dealing with demand response in particular for contingency reserves.

The reason that they only get half of their contingency reserve from demand response is because they have a rule that says we don't want to go above that because we're just not sure if we can get that much more.

Ian Baring-Gould: Great, thank you and thanks to the over hundred people who have stayed on for the webinar. That's all of the questions that we have thus far.

Thanks to the both of you for your presentations. Just to finish things up the Wind Powering America series is every third Wednesday, 3:00 Eastern.

The two that are coming up is on the 17th of July is "Hurricanes' Impacts on Offshore Wind Farms." Certainly a large issue when people look at the deployment of wind off the eastern coast of the United States.

Then in August, we're talking about "Small Wind Market Update." We'll get a readout of the Small Wind Report that the DOE - Department of Energy - has funded, as well as markets and reports and things of that nature.

As I said, the webinars are posted on the Wind Powering America web site and it takes us about seven days to get those out there. Please, if you found this presentation interesting, don't hesitate to pass it along to friends.

Lastly, a special thanks to the Department of Energy who funds the Wind Powering America initiatives and makes the webinar possible.

The contacts for all of us in WPA including Jonathan Bartlett from the Department of Energy is there so if you have any questions, comments or thoughts for future webinars, please don't hesitate to reach out to us.

Thanks again to Steve and Michael for their time and thank you all for joining in. We'll hope to see you again virtually at another Wind Powering America webinar.

Thank you so much and have a good afternoon. Bye.