The Western Wind and Solar Integration Study Phase 2

December 18, 2013

Coordinator: Excuse me. This is the operator. Today's conference call is being recorded. If you have any objections, you may disconnect at this time. Thank you.

Ian Baring-Gould: Great. Hello everybody. This is Ian Baring-Gould. Thank you for joining the December version of our Webinar series. In this one, we're going to focus on the Western Wind and Solar Integration Study Phase Two, which is an exciting new report that was released out of NREL just recently.

So we only have one speaker today and Greg is going to provide this overview of the study that came out of the phase one results and then a bunch of information and discussion that happened after that and was deemed by DOE that it would make sense to look at some of the results in more detail and that's where we come up with a phase two study.

So without further ado, I'll introduce Greg. Clearly, we can do Q&A and as always, we do Q&A from the - from typing it in so if you go up to the top of the bar, there's a Q&A tab. Hit that. Type in your question and click ask and then at the end of Greg's presentation, we'll take some time to do those questions.

So Greg Brinkman received his PhD in mechanical engineering from the University of Colorado, a Colorado guy. And he is currently a senior engineer here at NREL in the Strategic Energy Analysis Center.

He has done tons of work in the research area for modeling an electric power system and then air pollutant emission impacts due to renewable generation. And he's done lots of work in cost and other modeling in regards to the renewable electricity future study that NREL released, oh, about a year ago now, the SunShot Vision Study and then now the phase two of the Western Wind and Solar Integration Study. So Greg has been doing a lot of work in this area, modeling the electric system. And it's great to have him here to give the presentation. So Greg.

Greg Brinkman: Okay, great. Thanks a lot Ian. Let me switch over to my presentation here.

Ian Baring-Gould: Your slides are...

Greg Brinkman: Great. Can everyone see them now? Ian?

Ian Baring-Gould: Yes, we got you.

Greg Brinkman: Okay, great. So first thing I wanted to comment on for my presentation on the Western Wind and Solar Integration Study Phase Two is that this was a big team effort and it was sponsored by the U.S. Department of Energy and led by NREL and undertaken with industry partners.

And as Ian mentioned, this is an offshoot of the first phase of the Western Wind and Solar Integration Study. That study was completed in 2010 and the main question that it was looking to answer was whether we can integrate, tie penetration of wind and solar into the Western Interconnection and also what do we need to do to accommodate this and can we balance the load and generation.

We found that we could successfully integrate these penetrations if, and only if, certain operational changes were made. The most important of those operational changes are significant balancing authority cooperation and also sub-hourly scheduling between the balancing authority.

And this work has led to a proposal for an energy and balance market that's now in the process of being implemented between California ISO and Pacific Corp and I believe also Nevada Energy.

The graph on the right side of the slide here shows the worst week, the most difficult week of operation over the 3 years that they studied in Phase One. And you can see the high levels of both wind and solar penetration during this week and also it's a week during April and has a relatively low load compared to the rest of the year.

So you have a lot of wind and a lot of solar on the system which both have some variability and you have not very much - not as much load on the system. And what you have is this impacting the other generators significantly.

For the most part, it displaces almost all of the gas generation and it basically requires that the coal units change their output with relatively high frequency to handle that net load of the load minus the wind and solar.

And when this coal tries to follow a load like this, it is asked to do things that we call cycling. Cycling being both starting and stopping a unit and also changing the output of a unit over a relatively short time scale. And these coal units have to do things that they're not - that they don't always do in today's system.

They start and stop. They ramp down and operate at minimum generation levels more often. And this cycling can cause temperature and pressure changes in various components of the power plant.

And these can require more frequent repairs and maintenance and lead to wear and tear costs and the cycling could also have an impact on emissions. So basically the primary benefit of adding a megawatt-hour of wind or solar to the system is to displace a megawatt-hour of fossil fuel, primarily generation.

But there can be a secondary impact to the wind and solar and that's to increase the cycling at the existing fossil fuel generators. And what we really want to know is how big are these secondary impacts and do they - are they as significant as the primary impact of introducing wind and solar?

And so we undertook the Phase Two study to look at both the wear and tear costs of cycling and the emissions impact of cycling. So some recent studies have even claimed that wind actually increases overall emissions or that the avoided emissions from wind have been significantly overstated.

And so we wanted to really examine detail, both the cost of cycling and the emissions impact of cycling and also to do a number of scenarios to compare the impacts of both wind and solar.

So we - to do this we modeled the Western grid based on transition planning models and methodologies that were developed by the transmission extension policy and planning committee of the Western Electricity Coordinating Council.

So the results in this talk are really specific to that grid and the generator characteristics in the West. We developed a new emissions (data) set and also

new wear and tear cost data set that I'll talk about in a little bit more detail in a minute.

We also used commercial software called PLEXOS to basically simulate the operation of the grid on a five minute basis for the year 2020. We wanted to do a really rigorous analysis on this to understand these impacts and so what we did is we developed an emissions data set based on measured emissions from generating units that show how much extra emissions are emitted during a start or a ramp or also when you're operating a unit not at its full load.

Second, we also developed wear and tear costs and a wear and tear cost data set so basically comparing the cost of a start at a small sub-critical coal unit to, for example, gas combined cycle unit or a natural gas combustion turbine unit.

And we really wanted to model operations, the entire interconnections for an entire year because it's important that you capture the interchanges between balancing authorities and understand what happens in the whole system as - when the emissions at one plant go up or the costs at one plant go up it's possible that emissions and costs at another plant are going down or vice versa.

So we really wanted to capture basically the entire operation of the system in order to see this. So we had a - this whole work was reviewed by a technical review committee that met approximately every two months during this process and included members from the Western Electricity Coordinating Council, Western Governors Association, DOE, EPRI, a number of utilities and various other industry stakeholders.

And we also had working groups that focused on some of our other assumptions, particularly hydro and reserves modeling. Nevertheless, any grid modeling does have limitations and we can talk about some of those later.

Go into a little bit more detail to describe how we developed the emissions data set, we looked at the hourly emissions from every fossil fuel plant in the U.S. for 2008 or every fossil fuel plant that had the data and this is a continuous emissions monitoring data set from the U.S. EPA and every coal plant and all gas plants above 25 megawatts have this data.

So it accounts for a large majority of the generation from fossil fuel generators in the U.S. We studied CO_2 and NO_x and SO_2 for each plant, and we looked specifically at the emissions rate as a function of generation for each unit.

So, for example, that top right plot and in the bottom right shows an example of a start and so we looked at the initial - additional emissions due to starts and ramps. And to show you how this could be significant, on the bottom right is an example of combined cycle unit in the state of Colorado.

That red line is the predicted NO_x throughout a 20-hour period based on its generation levels. And the blue line is the actual NO_x, so you can see hour 1765, that unit got started and it reached its typical generating levels at hour 1767 and between there, we predict a relatively small amount of NO_x but the actual NO_x that we get is represented by that blue line and you can see that it's a lot more than expected.

So we wanted to understand that in more detail, and so we basically estimate that number for each unit and looked at how that unit might change and if operations, given changes due to penetration of winds and solar on the system.

So Intertech-APTECH did the work to develop the wear and tear cost data set and look at cost estimates in dollars per megawatts of capacity of the unit for units of various different types.

So this example chart shows that medians coal start costs of the - in different unit types that we looked at - I'm sorry, of seven different unit types that we looked at. And this includes both maintenance costs and capital costs of replacing things such as cracked boiler tubes, which you'll see in the picture at the top left here.

APTECH developed for us - and APTECH is a consulting firm that actually does this - they do this type of consulting to help generator owners understand how much it costs them to start a unit. It's not an obvious number that they incur, an obvious cost when they start a unit because some of these costs can be incurred months or even years in the future as you (increased) fatigue on the materials continues to crack and cause additional maintenance and replacement problems.

And so APTECH does this for generator owners to help them understand, and they basically analyze their data set of about 170 generators in North America that they had data for to help us understand what typical wear and tear costs were at different units in the U.S.

And they estimated both an upper bound and a lower bound on the cost per start and the cost per ramp of a unit. And so we'll present those - I'll present those later in this talk.

We wanted to look at a number of different scenarios and consider a number of different scenarios, so we looked at five hypothetical scenarios in the Western United States. There's a no renewable scenario which is not shown here because there're no renewables in the West.

And we included this scenario as a framework for comparison. And then the other four scenarios are the TEPPC scenario, which reflects the estimated

renewable layout of the Western grid based on existing state RPSs at the time they made the data set.

And this is about 13% total wind and solar, 9-1/2% wind and 3-1/2% solar, and then we also modeled three higher penetration scenarios, both a high wind and a high solar scenario and a high mix scenario.

And these are all 33% wind and solar penetration levels and the high wind scenario is 25% wind and 8% solar. The high solar scenario is the opposite, 8% wind and 25% solar, and the high mix is an even mixture of wind and solar.

In Slide 9 it shows the megawatts of installed capacity in - or each type in each scenario. I'm not going to go into detail on this slide but it will be available for you guys to look at.

So we sited all the wind and solar in the U.S. portion of the Western Interconnection because that's where we had data. And also the concentrating solar power is assumed to have six hours of thermal storage, so basically the salts that are heated up from the solar energy are assumed to be able to store that energy for up to 6 hours of full load usage of the unit.

The original basis for this case is the WECC TEPPC 2020 PC1 transmission planning case. And we did make some updates to that case based on a few updates that were in the pipeline at WECC when we started this study.

The next slide, this shows the transmission expansion for each scenario. This is - this study was not a transmission planning study. But in order to realistically model cycling of generators, we needed to have a realistic

transmission grid that would be able to get the power from the locations where the wind and solar was assumed to be to the locations where there's load.

So in this picture, the grey lines that are connecting the regions in the West are the original capacity between the different regions and the black outlines that some of the lines have are additional capacity between those two zones.

So we get a different transmission built out for each scenario so that we had sort of a realistic framework for comparison between scenarios. And there's more detail on this in the report but I'm not going to talk about it in detail today.

Next I'm going to show a few slides looking at the spring and the operation during the spring. Spring is the most challenging time for operations in these high penetration renewable scenarios because of what the existing units on the system are asked to do.

This slide shows the no renewable scenario in the spring. And you can see that operation is relatively simple during the spring in a no renewables or in a very low renewable scenario.

On the bottom in red, in this chart, you have basically a week's worth of operation and it shows what - at each time, what generating units are providing the energy to the system.

And so at the bottom of the stack you see the nuclear generation, which is basically flat during the entire time period with the exception of an outage that occurs for maintenance on the unit on March 29th you can see there.

The coal generation is the blackish color above the nuclear and you can see that it operates relatively consistently as well. And that's true also of the hydro. The generation that changes to respond to changes in load is primarily the natural gas combined cycle units which can handle this type of flexibility a little bit easier than the coal units can and they're also more expensive to operate than the coal units. So they're the first units to be turned down in this scenario.

Now as I step forward to the high wind scenario, you'll see a very dramatic difference in the looks of this chart. Now this shows a scenario of 25% wind and 8% solar on an annual generation basis. But during this week, the penetration levels are significantly higher of the wind and solar.

And what you'll see is the red on the bottom, or the nuclear units, are still operating relatively consistently because that's what we require in our modeling. Above that, you have the coal units and you'll see that those units actually do respond to changes in load and changes in renewable generation quite a bit, particularly on a sort of weekly scale as they - many of the units shut off during the early portion of the week.

As you get towards the middle portion of the week when there's more wind available, and then turn back on later on in the week. You have a significant amount of hydro generation during the spring time period also. And you have also the PV and obviously the blue is the wind.

And so what you see here is very little gas generation and you see the coal generation responding to the changes in both load and wind generation. This is because the gas generation is more expensive to run and so it is the type of generation that is turned off first.

Now, in the high solar scenario, you'll see a slightly different look to this in that you still have consistent nuclear generation but the coal generation changes on a sort of daily pattern instead of a weekly pattern. And this is because the solar generation obviously has a very consistent diurnal pattern in that, you know, it's out when the sun's up and it's not there when the sun's down with the exception of the concentrating solar power which has some storage.

And most of the thermal storage from the CSP generators in the spring timeframe is used in the evening hours and so it's really during those midday hours that our load goes the lowest which is the opposite of what happens today, our net load.

And so what you have is the coal generators in general are staying online and they are ramping down every day to provide their minimum generation levels around noon and then ramping back up to provide their maximum generation levels in the evening.

And so the next slide shows some aggregate numbers from the whole hear comparing cycling at coal - natural gas combined cycling units and natural gas combustion turbine units.

So what you'll see in the top left is the capacity of generation that is started at some point during the year. So this is basically a metric of how much these units are starting. And you don't see dramatic difference particularly in the coal between the scenarios as they start a few more times during the spring when you look at these difficult weeks, but other than that, they do not start and stop a whole lot more than in the no renewables case.

The combined cycle units in the relatively low penetration TEPPC case, you see a noticeable increase in the amount of capacity started but in the other cases, you don't see that increase.

With the combustion turbine units that often start just for a few hours at a time, you see actually a reduction in the capacity started of these units in the higher wind scenarios. And that's because these units are more expensive to run so if you can shut them off, you want to.

In the high solar scenario, what you see is a lot of solar generation online until sunset. And then you see a very sharp requirement of the fossil fuel generators on the system around sunset to handle that - the load that's on the system and you don't have as much of the PV generation.

And so you see a lot of combustion turbine generators starting for that relatively brief period of time where they're necessary and so you see more starts at the combustion turbine units.

On the bottom, it shows the hours online at the average unit per start. And you'll see that there's not a dramatic change. There's a noticeable decrease in the combined cycle units in the number of hours online per start.

But at the other units, you don't see dramatic changes. The most dramatic change of any unit type, of any cycling type on the system is the coal generators and their ramping usage.

In the no renewable case, you see very little ramping of coal generators. They basically sit online and they operate at their maximum capacity. As you start introducing more renewables into the system, you really start demanding more from those coal units and you demand them to ramp their generation down to

their minimum generation levels and back up, particularly as you get to the higher 33% cases and particularly in the high solar case.

And so that's really the biggest sort of regime change you see here in the operation of the fossil fuel units, is how these coal units are ramped to provide load during the year. And you'll see that the ramping at the combined cycle and the gas combustion turbine unit doesn't change all that much.

This next slide shows a little bit - in a little bit more detail what exactly is happening when these units - when the total coal generation is reduced. You'll see in the no renewable scenario, this plot shows the dark line, the outline at the top of each graph, shows the amount of capacity that is online.

And the shaded region shows the amount of actual generation coming from the coal generators. So in the no renewable scenario, the shaded region and the solid line are equal. And that's because every coal generator that's online is generating as much as it possibly can in that scenario.

In the TEPPC scenario, you see pretty close to that happening although on March 29th, you see that some of the online coal capacity, the coal units that are on and operating, some of them are turned down a little bit lower than our maximum generation levels.

Now, in the high wind scenario, you'll see that that solid line goes down significantly during the middle of the week and that's because those generators are actually being turned all the way off and then those generators or other generators are being turned back on a couple of days later as the net load requirement goes back up.

And you'll also see during some of those days that the coal units are actually turned down to their minimum generation levels during the day or in the evening.

You'll see that a lot more in the high solar cases on the bottom right. What you see there is that, yes, during the middle of the week, some of the generation, some of the coal generation is turned off but the primary thing that you see here is the shaded regions that are the actual generation levels and they are turned - the coal generation is turned down every day and then ramped back up to capacity each night to generate at maximum capacity.

So you see a little bit more ramping in the solar case and a little bit more start/stop cycling in the high wind case. This slide shows what is displaced as you add renewables under the system compared to the no renewable scenario.

The top scenario you see here is the TEPPC scenario and as we add renewables onto that system, we are displacing a little bit of gas combustion turbines and a large majority of what we are displacing is natural gas combined cycle.

Less than 10% of what is displaced is coal generation. And that's because that natural gas generation costs a lot more and so that's what you turn off first if you're trying to optimize the total cost of serving a load on the system.

In the high wind scenario, as you get your penetration levels up to 33%, you've displaced a lot of the combined cycle generation already and then you're starting to displace coal generation. And as you change your mix of wind and solar, you displace less and less coal compared to the high wind case and that is because the time of day that the solar is available is during the day

and there is more natural gas online during those hours and so you displace more natural gas compared to the wind scenarios.

So the upshot, the real questions we were trying to answer about cost and emissions, we'll get to those here. And first question we want to answer is how are emissions impacted by cycling? And system wide, the emissions impacts of cycling are relatively small. If you look at the CO_2 impact of the - and this is all for the high penetration, 33% cases, and that's 33% penetration in the United States.

But for the entire Western Electricity Coordinating Council region, which includes a very small part of Mexico and a significant part of Canada, those penetration levels are approximately 26% and because of changes in imports and exports, we had to consider emissions changes over the entire interconnection.

So at 26% penetration of wind and solar, leads to a 29% and 34% reduction in CO_2 emissions. This number is higher than the 26% penetration because some of the generators that are online currently are nuclear and hydrogenations and those have obviously no CO_2 emissions whatsoever. And so you're displacing gas units primarily that do have significant CO_2 emissions.

The impact of the cycling on the emissions, it basically has no impact whatsoever on this number and you see the exact same 260 to 300 billion pounds of CO_2 reduction. For the NO_x, we see a slightly different story but not dramatically.

You see that the total NO_x reduction is a little bit less than the total CO_2 reduction. We're seeing about a 16% to 22% reduction in the NO_x and this is

because coal units emit 10 times or more NO_x compared to gas units per megawatt-hour.

And since we are primarily displacing natural gas units, we don't see quite as an aggressive reduction in the knocks compared to the CO_2. The impact of cycling is actually to reduce NO_x by more than we would have otherwise expected. And I will explain that reasoning in just a minute.

For the SO_2, we see 14% to 24% reduction throughout WECC and the cycling impact is still quite small. So of the 80 to 140 million pounds that we reduced by adding renewables to the system, the additional impacts of cycling cause an addition 3 to 4 million pounds.

So it's basically just a couple of percentage points - a couple of percent increase in the SO_2 compared to what would've happened if there was no impact of cycling whatsoever.

So to answer the question of why the NO_x reductions are actually higher than you would expect, I'll show this plot here which is a plot of the average NO_x emissions rate, different generations types in the Western Interconnection.

And it's as a function of the fraction of maximum generation that the unit is producing at a given time. And so you'll see that at coal units in the West, is for example, if you're operating at 70% of your capacity, you are emitting NO_x at somewhere in the neighborhood of 2.4 pounds per megawatt-hour.

Whereas, if you're operating at 100% of your maximum generation, you are - emit NO_x at approximately 2.5 or 2.6 pounds per megawatt-hour. And this is for the average coal generator in the West.

And so actually operating at part load means you're emitting less NO_x per megawatt-hour that you generate. And in the base case and in the no renewables case, what you're doing is you're operating always at that - almost always - at that 100% level and not very often at those lower levels.

But in the higher renewables cases, you'll see additional operation at those lower levels and that's why you're actually producing less NO_x than you otherwise would've expected.

I also have a few slides here of the average emissions rates from each type of generator and this is from the perspective of the generators. So what - how that generator emissions rates change and you'll see that there's not a whole lot of difference in CO_2 rates.

And I'll go through these slides relatively quickly so we can get to the cost to impact slide. And for the NO_x, you see a little bit more of a difference. And in combined cycle cases, they - NO_x rates increase a little bit for the combined cycles and effects can be different in wind versus solar for the combustion turbines.

For SO_2, we see very little change in the emissions rate compared to base case although it does depend on whether it is wind or solar we're talking about. So now let's move on to the cost impacts of cycling, the wear and tear cost impacts from cycling.

First I wanted to comment on that electricity costs include both capital and production costs. Here we are really focused on the production costs or you can think about it as the operation costs or what - how much it costs to operate the system, not how much it costs in capital to install a bunch of units.

Or we're not looking at the capital costs of all this wind. We're looking at how it impacts the system. That was really the focus of the study. And so that production cost includes both fuel, variable O&M or variable operation and maintenance costs, and those additional cycling costs.

And that's - I'm going to talk about from the next couple of slides. Those cycling costs make up somewhere between 1% and 7% of the overall production costs depending on which scenario you're looking at and also depending on where you assume the lower bound or the upper bound cycling costs that the APTECH analysis came up with.

Cycling costs in the scenarios for the Western Interconnections range from $271 to $800 million and this is out of total production costs in the West of a little less than $20 billion in the no renewables case.

So what you'll see here is that production cost goes down quite a bit in the high renewable penetration cases and that's because these units don't really have any operating costs. Their primary cost is the capital that it costs to install them.

And the next slides will show some of the differences between the scenarios. Cycling costs in the different scenarios increase by between 13% and 24% compared to the no renewables scenario. And so what you see here is the range of cycling costs for the different scenarios.

And one thing you might notice is that the 33% high mix scenario actually has lower cycling costs than the 13% penetration TEPPC case. So the wind and the solar really play well together in the high mix scenario. And actually it - there is less cycling costs in that case compared to the TEPPC scenario.

And the total amount of cycling costs that are induced by wind and solar penetration are between $35 and $157 million per year in the Western Interconnection.

And so that's how you can look at these numbers from a system perspective. And from a system perspective they are relatively small. The increase in cycling cost is relatively small compared to the total production cost of the system.

You're looking at numbers of less than 2% increase in costs compared to if you did not take cycling costs into account. Another way to look at it is from the generator perspective. The average fossil fuel generator plant sees an increase in operation and maintenance costs of somewhere between 47 cents and $1.28 per megawatt-hour of generation.

Now, to give you a frame of reference, a typical coal plant might cost about $20 per megawatt-hour of generation total including fuel and operation and maintenance costs. And a natural gas plant might cost somewhere between - somewhere in the neighborhood of $30 per megawatt-hour.

So these are increases of a couple percent on the generation - the cost to the generator per megawatt-hour of generation. And you can see in this graph on the left, is the lower bound and on the right is the upper bound in the different scenarios. You can see how that changes between wind and solar in the different scenarios.

So in the no renewable scenario in the lower bound, we're looking at about 50 cents per megawatt-hour in cycling costs because in today's system, even with no renewables, there is still a cycling cost and that's captured here but that cycling cost increases to about a dollar in the 33% scenarios.

If you look at those cycling costs per megawatt-hour of generation, the TEPPC, the 13% penetration scenario, is always significantly lower than the cost per megawatt-hour in the 33% scenarios.

You will see that the wind and solar play nicely together in the high mix scenario as the high mix scenario always have less cycling costs and also less cycling cost per megawatt-hour of generation compared to the other 33% scenarios.

And also you'll note here comparing the ramping, the startup fuel on the startup costs, that it's the starts and not the ramps that drive the wear and tear costs.

The next slide shows the cycling costs per megawatt-hour broken down by the type of generator. And this slide looks a little bit surprising on first inspection because the coal units actually have the lowest cycling costs per megawatt-hour of generation.

The coal units tend to have the highest cycling cost per cycle but they are online for many more hours per cycle. You typically leave a coal unit on for a week or a month or longer when you're generating with coal compared to a natural gas combined cycle unit which you might only leave on for a week or two or a natural gas combustion turbine unit which are relatively cheap to start but you might only run them for a couple of hours before you turn it off again.

So when you look at the cost per megawatt-hour, you see the coal units actually have the lowest cycling costs and that combined cycle in the gas turbines are - have higher cycling costs and the impact of adding renewables

is more significant on the combined cycle units because these units are asked to start noticeably more as we penetrate renewables onto the grid.

The combustion turbines, cycling costs of the combustion turbines, like I mentioned earlier, these units are sometimes in high wind cases, actually started less frequently and used less frequently and the cycling costs can actually go down.

In the higher solar cases, you see that the cycling costs will typically go up per megawatt-hour and that's because these units are run for even a shorter amount of time as they're often started at approximately sunset and turned off soon after that, whereas today, they're typically started before peak load occurs and maybe in the, you know, soon afternoon and run until early evening.

So that's the generator perspective and then from the system perspective, the cycling costs are relatively small. In the 33% wind and solar scenarios, we have about $7 billion in avoided fuel costs compared to an increase in cycling costs of $35 to $157 million, so it's much smaller.

Just a quick reminder here that the capital costs are not reflected here. We're really just focusing on the operational costs and understanding whether cycling is a big deal from a system perspective. So this is not an analysis that looks at whether or not wind and solar are economically beneficial overall, over the - just focusing on the cycling costs.

From a system perspective, we can also look at this as the production cost change due to the penetration of wind and solar. And so this graph shows the production cost change for each megawatt-hour of wind and solar that's penetrated onto the system.

When you put wind and solar on the system, production cost changes somewhere between - somewhere in the neighborhood of $30 per megawatt-hour. Now, cycling - this is sort of the reduction due to penetration of wind and solar.

Cycling costs reduce that reduction, so cause it to be 14 cents to 67 cents less per megawatt-hour of wind and solar, so as you can see from the chart, it's the green, yellow, and red are the different cycling costs. It's quite - the impact of cycling costs is quite small compared to the reduction in fuel costs that wind and solar bring to the table.

Next up, a little bit about the difference between wind and solar and how wind and solar play on the system and why this might not be - cycling costs might not be as dramatic as one might expect.

First of all, aggregation reduces variability. So if you look at just one or two plants, solar plants, in Southern California, for example, on a partly cloudy day, this plot shows that in the hyphenated - the dashed - lines, the orange and the yellowish ones are just one or two plants and it shows the variability throughout a typical partly cloudy day.

And what you'll see is a whole lot of variability and a whole lot of changes in output on a, you know, 5-minute kind of time scale. But as you start aggregating the output of a number of different plants, as you would do if you're a system operator and looking at the total PV generation in your area during the day, you start looking more at the 25 plant line or the entirety or Southern California which is the solid line.

And in that line you really don't see nearly the amount of variability that you see on the individual plants. Also we looked at the amount of reserves that might be required. Reserves are generation capacity that is online and available to be used by the system operator at a given time.

And these are different types of reserves, the (contingency) reserves deal with contingencies or when generators or transmission lines go out of service unexpectedly. And that requirement was not changed for the different scenarios.

The regulation is the reserves that are required at a sub-5-minute time scale and these don't - these change a little bit between the scenarios but not a whole lot. The flexibility reserves deal with more like an hourly time scale and looks at how much additional capacity you want to have available to deal with forecasting error for the different scenarios and those numbers do go up significantly.

And those requirements are higher for the high wind scenario and high solar scenario because short term and medium term solar forecasting is typically better than short term and medium term wind forecasting.

Next slide looks a little bit at curtailment. And so what you'll see in the low penetration TEPPC scenario, curtailment was modeled to be quite low. In a 33% scenarios, we're looking between about 1-1/2% and 5% curtailment and what you'll see is that the (balance) mix of when this is a high mix scenario has a lot less curtailment than if you have mostly wind or mostly solar.

So again, same with the cycling. It impacts the high - the wind and solar play well together. So some of the conclusions before we open it up for questions, I've mentioned most of these already. The emissions impact for CO_2, SO_2 and

NO_x induced by cycling are a very small fraction of the overall reduction in emissions due to wind and solar penetration.

Wind and solar do increase cycling costs by $35 to $157 million per year. From a fossil fuel generator's perspective, this cycling O&M increases by about 50 cents to $1.30 per megawatt-hour, which could potentially be a significant number.

From a system perspective, the cycling reduces the production cost savings of wind and solar by 14 to 67 cents per megawatt-hour of wind and solar. So from a system perspective, this is a pretty small number and it's not a big deal when you look at it from the system perspective.

The wind and solar impacts fossil fuel plants differently but the total production costs savings is relatively similar. And I just wanted to remind everyone again, the conclusions from this work are specific to the grid footprint we studied which is the Western Interconnections of the U.S. and, you know, some of the conclusions may apply to other areas but we don't know for sure.

So thanks a lot for your time. This is my contact info and I believe that Ian is going to post these slides and so you should be able to get in touch with me with this contact information. And that is the website for the study and there's a two-page version. There's a 20-page version. And there's - I forget how many - 100, 200-page version of the report. So depending on which one you're interested in, you can find them all at the webpage. So thanks a lot for your time everybody and I think Ian's going to open it up for questions.

Ian Baring-Gould: Yes, exactly. So thank you, Greg, for the overview of the project. We've got a bunch of questions here for folks so we'll dive right into those and it might

mean going back to some of your slides. So why don't we leave those up? The - so, Corrie, if you could go back to Greg's slide, that would be great.

So Debra Jacobson, under the current law and regulations, natural gas, combined cycle plants are replaced by more than coal plants because they're more expensive to run. However, if CO_2 limitations are placed on existing coal plants as proposed by the current Obama Administration, to what extent will coal plants be displaced instead of natural gas plants?

So it's a pretty specific question and I'm not sure if you can answer it, but if you could talk a little bit about how you think further limitations on CO_2 production would impact the way these - the choices in plants would change.

Greg Brinkman: Okay, so there're a couple of questions maybe imbedded in that, one of which is, you know, what if these coal plants choose to retire? And we did not answer that question in the study. However, you know, we wouldn't expect the cycling costs necessarily to change dramatically or to increase dramatically as typically gas units can cycle for cheaper and less emissions impact compared to coal units.

However, from a, you know, displacement of existing resource perspectives, we did do a gas price sensitivity which also shed some light on what might happen if coal prices increase significantly or if the cost to operate a unit increases significantly which is what would happen if you put a carbon tax or if there was some kind of cost to carbon in existence.

And so we have, in this plot is actually a sensitivity on what gets displaced if you look at gas that costs half of what the projections look like and also gas that costs double what the projections look like.

So in that top sensitivity there, you have the $2.30 gas and you don't see a whole lot of difference in what is displaced. And on first inspection, this looks kind of surprising. What's really happening is that the coal is already in the base - so this is - again, this is in the - this is the high mix case I believe.

And it is the - this is the difference between the high mix case and the no renewables case. And basically in the no renewables case, you already chose to displace a lot of the coal with gas. And so as you put renewables on the system, there's not that much coal left to displace and so you displace a relatively small fraction of the coal.

So we expect the results to not be shockingly different depending on what kind of carbon costs or CO_2 limitations are in place or what the existing generator network looks like.

Ian Baring-Gould: Great.

Greg Brinkman: Yes, a reasonable answer.

Ian Baring-Gould: Yes. No, I think that does and this figure gives a pretty good understanding of the magnitude of the impacts as the - either coal gets more expensive or natural gas gets more expensive. Okay, great.

From Heather Rhoads-Weaver, could you explain a little more about the curtailment? Which resources would be curtailed and what are the economic impacts of that curtailment?

Greg Brinkman: Yes, sure. So let me find a different slide here actually. Now, we don't - we intentionally do not report which types of resources are curtailed because the

way our model looks at it, they're all zero cost resources and so there's really no reason for the model to choose one resource over the other to curtail.

That being said, you know, if you look at the high solar case, for example, and you look at the curtailment, that curtailment in the high solar case is always happening right in the middle of a day.

So presumably that primarily would be coming from the PV generators. Now, of course, you could curtail the wind instead if you had some reason to or if there was some incentive for the wind - for the solar to produce instead of the wind.

But for the most part, there will be small congestion issues and other things that determine which resources are curtailed. So it's not really a question I can answer very easily with this modeling and it would depend on market structures and things like that.

The economic - the rest of the question - the economic impact of the curtailment, the curtailment - so there're two economic impacts. One is that, you know, in the market like CAISO for example, the marginal price that those hours will change to - will be zero, basically or even negative if there's some kind of tax credit justified - to justify additional generation from the wind plants.

And so that will change the amount of money that the existing resources and the new resources are getting paid. So there'll be that impact, the impact on prices that these generators are getting paid, and there'll also be the impact on the economic justification that went in solar. And I will leave that sort of - leave that open to interpretation as to whether 3% or 5% is a big significant number or not on the economic impact.

Ian Baring-Gould: Great. Thank you. A question from John O'Sullivan. Is there any way to estimate the changes in costs for another grid network, for example, if another region depends more on nuclear and little on hydro, do cycling costs change and curtailment rates change significantly or do you think those are, from a plant perspective, those are going to be relatively similar across the country?

Greg Brinkman: So I think that what they're depending on actually might have a smaller impact than how big they are. In this study, we basically assume that there was additional balancing area cooperation within the West and that they're able to import or export electricity if the economics justifies it.

If you're looking at a small, vertically integrated utility and trying to integrate a whole bunch of wind and solar and you don't cooperate with you neighbors, you just - you don't import depending on what the prices are, you can have a significant impact because you don't benefit nearly as much from that aggregation I showed earlier.

So, you know, we can't answer that question with any certainty. But my feeling from looking at this ultimate modeling is that results would potentially be a little bit different if a region depends on a slightly different mix of resources.

But the results could be more significantly and substantially changed if a region doesn't play well with its neighbors or doesn't interact much with its neighbors and has a relatively small footprint and a relatively small number of generators with which to respond to changes in that net load.

Ian Baring-Gould: But basically, you don't see or you wouldn't expect that the generators themselves would have higher cycling costs, per se.

Greg Brinkman: Probably not dramatically different. The nuclear question I can't answer because we did not have cycling costs on the nuclear generators and we basically assumed that they were completely incapable of cycling. So if a region depends more on nuclear, that might be a tough answer.

Ian Baring-Gould: Okay.

((Crosstalk))

Greg Brinkman: ...coal, I don't think there's going to be a dramatic difference.

Ian Baring-Gould: And it would force higher analysis cycling on the coal and gas generation because of the higher...

((Crosstalk))

Greg Brinkman: If you assume that the nuclear can't cycle which is generally the case in the U.S. but, of course, there are countries that operate primarily on nuclear generation and their nuclear generators are able to cycle more effectively.

Ian Baring-Gould: Right. Okay. So a kind of a follow up from Debra, we constantly hear the refrain out in the deployment space that wind power actually increases emissions or the reductions that you don't get are real because of the need to back up fossil fuel generation and the cycling costs.

I think the study clearly says that that's not the case. But, Greg, how would you respond to someone standing up in a crowd saying, "I've been told that you get no environmental benefits from wind, from a CO_2 perspective, because of backup and curtailment or and cycling," sorry.

Greg Brinkman: Yes, sure. So I would answer this question by saying there're sort of two reasons why you still get air emissions benefit. One of those reasons is that you don't need one to one backup. If you have a gigawatt of wind on your system, you do not need a gigawatt of combined cycle generation just sitting there waiting to, you know, online but not generating.

You don't need that much backup capacity. You need a fraction of your capacity available as backup and that's - I talked about that briefly with the reserve numbers and how much capacity you need online ready to back it up is a small percentage of the capacity, the renewable generation at that time.

So basically the first point is that you don't need backup for every megawatt-hour of generation that you're producing. My second statement is that even if you do have the generators back down, particularly the coal generators, when a coal generator is operating at 50% of its capacity, it's producing - for most coal generators, it's producing less than 50% as much emissions than when it's generating at 100%.

So if it's generating at half load, you might be producing 47% as much emissions as if it's generating a full load. So even if the generators are providing backup, you are - they are not producing nearly the level of emissions that they would be otherwise. And that's why you're still getting a benefit.

And I'll also say on the startup question, there's really not that much CO_2 released upon starting units. And so the cycling impact regarding CO_2 in particular, are not even close to important and for knocks and SO_2, they're basically close to important but not quite rising to the level of significance. So

the short - two reasons. One is you don't need full backup and, two is, even when you're providing backup, you're saving emissions.

Ian Baring-Gould: Great. And then reference to study to people who want more information.

Greg Brinkman: Yes, definitely.

Ian Baring-Gould: Okay, one last question. From (Nider Sien), I believe, for high wind and solar scenarios, while the cycling cost of system levels seems to be small, that does not consider the negative impacts of thermal units producing more cycling and operating in a much lower capacity factor which will have negative impacts on the return of capital investment.

Greg Brinkman: Yes, and this is a question not just about cycling but about sort of markets in general. If you look at these high penetration scenarios, you are putting a whole lot of zero cost generation into the market.

And when you put - if you're looking at a market and not a vertically integrated utility, when you put a bunch of zero cost resources into the market, you suppress prices. And that's true whether you're looking at nuclear generation or even inexpensive base load coal generation or renewable generation.

If you put a lot of that type of stuff into the market, you are going to suppress prices and it will have an impact on the other generators. You know, so we have upcoming work that sort of looks - it's going to look in a little bit more detail at some of these market issues.

But there will certainly be impacts on existing generators and they will be operating like (Nider) said, at a lower capacity factor and it will be harder for them to make money in the energy market.

It's possible that some of the ancillary service and capacity markets may be necessary in order to incentivize these generators to not retire or incentivize new generators to come into the market.

So energy prices themselves will likely go down. And that's true, having nothing to do with cycling. And so it will - and the existing generators will be displaced. So in addition to cycling more, they generate less and make less money in the market. And so there might be additional market mechanisms that are required if these prices go down.

Ian Baring-Gould: Great. Thank you, Greg, and thanks again for giving the presentation. To everybody, we didn't have huge attendance because, I guess, at least Heather Rhoads-Weaver indicated that the California Energy Commission is having a big webinar at exactly the same time.

So as always, these Webinars are posted on the website as you can see there. And I'd certainly encourage people who have seen this and think their colleagues be interested, to point them towards this.

It takes about a week to get this up there and then people are free to view it at their pleasure. For upcoming Webinars, again, the third Wednesday of each month at 3:00 Eastern. The next one is going to be on workforce, focused on a recent paper that was published by NREL that is the first real survey of the wind workforce here in the United States and talks about what it is, who is part of that and then what our expectations going forward in regards to the wind workforce.

And then we'll have a quick overview of the Collegiate Wind Competition which is scheduled to happen in the spring. In February, we're doing an introduction to the Wind Vision. So everybody who isn't aware, DOE has launched with the wind industry, primarily AWEA and others, a revamp of the 20% report that came out not quite 10 years ago.

And so it's a large effort that was kicked off at WINDPOWER last year and lots of people have been working on it and so we're actually at the point now where we can start making some presentations and rolling out some of the information around that.

So the 19th will provide an overview of the Wind Vision and bring people up to speed kind of as we ramp up to WINDPOWER again, where the next version will be released.

And then in March, we have the return of the wind power effects on property values with Ben Hoen's recent work and his recent paper on that as well as some work coming out of the Northeast that will kind of mirror very well with the work that Ben has been doing.

And so we've kind of pushed that back to allow the work that's coming out of the Northeast to be done and so we'll have the two-for in that case in regards to property values.

So again, those are coming up over the next couple of months and certainly encourage people to attend if they - when they can. So as always, a special thanks to the Department of Energy for supporting the webinar series and the stakeholder engagement and outreach activities. Thanks again to Greg for taking the time to present to us.

If you have any questions, thoughts or additional Webinars that you would like to see, Patrick Gilman, myself or Suzanne would be happy to talk to you about that. So thanks again. Have a great day and a wonderful holiday and we'll talk to everybody again in January. Thanks very much and have a great day. Bye-bye.

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