[Speaker: Kristen Ardani]

Cover Slide:
Thank you everyone for joining us today for the DG Interconnection Collaborative (DGIC) informational webinar. We're fortunate today to have speakers Michael Coddington of the National Renewable Energy Laboratory (NREL) and Robert Broderick of Sandia who will present recent research findings related to distributed PV interconnection mitigation measures and costs.

Slide 2:
So with that, I want to introduce our speakers for today. Michael Coddington is currently a senior electrical engineering researcher and principle investigator in the solar energy technologies program system integration area for NREL. With a focus on solar interconnection technology, codes, and standards and policies, Mike has a significant background in DG interconnection and understanding how to add more PV to the utility system.

Then we have Robert Broderick of Sandia National Lab. Before working for Sandia, he worked as a consultant for TRC Engineer Inc, focused on solving problems for PV project developers, performing comprehensive grid integration studies for utility clients. He also worked as a senior power engineer in P&M's distribution planning department and customer generation department. Mr. Broderick is a professional electrical engineer and a member of the IEEE Power and Energy Society. So with that, I would like to go ahead and turn it over to Michael Coddington for our first presentation. Mike…

[Speaker: Michael Coddington]
Slide 3:
Good morning or good afternoon wherever you are. I appreciate the opportunity to talk to you, this audience today. I wanted to talk about not only mitigation practices, but also just interconnection screening and the follow on mitigation practices.

Slide 4:
There are 21 utilities in the U.S., NREL and Epri as well as Sandia National Labs that are partnering with these organizations under the California Solar Initiative and the Department of Energy looking at ways to improve screening methods, and one of those tasks involved in this project is to look at the current screening practices across the United States.

Slide 5:
Initially, we had talked about just working within California on this project, but it was evident soon after that it would make sense to take a look at screening practices and the entire interconnection practice across the US, and so that's what we did with NREL and Epri and Sandia.

Slide 6:
As you can see, the first step in this project is to document current practices, and ultimately what we're trying to do is analyze a number of distribution feeders and come up with some alternate screening methods. As we know, feeders are all different. Some feeders can host many megawatts of PV without much trouble.

Others don't have it quite so easy, so we want to just understand the differences between the topologies of meters.

Slide 7:
Now we interviewed 21 utilities across the U.S., and we broke those into four regions, the California area, southwest, central US, and the northeast. We kind of did this so that as we detailed the information that came from various utilities, we wanted to kind of just put those in regions and not just point towards one utility or another, but to kind of look at a regional area.

Slide 8:
So the simplified process as it was shown here, this was pretty typical for many utilities in the U.S.

A customer or a developer applies for PV interconnection. Most of the time, screens are applied. After that, there may be supplemental studies, and any time after screens are applied or supplemental study, the application may be approved. If those screens or the supplemental screens are not approved, then we typically go into the detailed impact study phase where we look or the utility looks at ways of mitigating concerns they have. And ultimately, if those are mitigated, then the application is approved.

Slide 9:
So the questionnaire that we used for interviewing these 21 utilities have kind of six main areas of focus, starting with application, screening procedures, supplemental screening if applicable, the utility concerns related to interconnection.

When we looked at the impact study approach and software use by the utilities, we looked at kind of the common mitigation strategies used by these utilities. I'm going to talk about each of these six bullets in the next few slides.

Slide 10:
When we started this series of questionnaires in 2013 between NREL and Epri, I think we were a little bit surprised at how many utilities were interested in joining and being part of this study so that they could understand what other utilities are doing and look to adopt perhaps some best practices, just see what their neighbors are dong. So we started with the application process, which is important.

I think it's interesting to see that most utilities have time limits. Certainly many utilities follow state rules, and that can be a very good thing if they're well thought out. A

number of utilities have multiple tiers of applications depending on the size and the type of technology of the distributed generation. Many utilities also have inverter based applications, typically for photovoltaic systems, and that can be helpful, and perhaps the approval can come more quickly. Many utilities post their applications online, and some even allow online submittal and tracking, which can be very helpful.

And you know, it's interesting to see that there are some utilities that are not even allowed to charge a fee for certain applications, but most do have at least a nominal fee.

Slide 11:
Most utilities apply screening procedures for applications, especially those applications for interconnection that are smaller. Some larger interconnection applications skip the screening because they're just really not applicable, and they go right to detailed impact studies, but most utilities again follow some version of the FERC screens, and you can see some of those down below. One that we focused on particularly as a big part of the focus of this project is screen number one, kind of the – we call it the penetration screen.

So in this case, aggregated distributed generation is less than 15 percent of people out on a line section or feeder. If that's not met, then the screenings are failed, and that's going to change somewhat from the peak load to looking at minimum daytime load based on a recent FERC decision in late 2013. I found it interesting that one utility didn't seem to use screens at all, and that was a bit surprising, but again, there seemed to be differences between most utilities, other than those that follow very closely to the state rules and procedures, which actually seem to work well for everyone.

Slide 12:
This diagram gives a little more detailed view of what the process looks like, and I'll be kind of talking through this various stage – the various stages of this graphic, but you see the starter, and that's where you've got an application that's filled out. And once that's completed and the utilities check that over, typically these fast track screens are applied, and if they're met, typically the utility would approve that interconnection application.

If the screens are not met, many utilities apply what might be called supplemental review screens where they take a little deeper look at the application to determine if there's a way to approve that interconnection application and allow for faster interconnection. If the supplemental review screens and the fast track screens are all failed, then detailed impact studies are the next phase. And utilities will use software modeling, and then apply mitigation strategies, and we'll talk more about those mitigation strategies in a few slides, but they'll apply those mitigation strategies, run the model again, and come to a point where the application can be approved.

And there should always be a way to find a way to mitigate a problem and seek approval. It's generally just a matter of time and typically money.

Slide 13:
So in terms of supplemental screening, not all utilities have used this, but this has become recommended by FERC. But it's really used to pass some of the applications that failed the fast track screens as an example, and they have a transformer that's overloaded at a residence, but a utility engineer could look at that failed screen and say, "If we change the transform route, then we know we can use that screen, and we can approve it." The cost of the transformer would typically be born by the interconnection application customer.

And you know, there are other examples as well, and they're often quick and fairly inexpensive solutions rather than moving into detailed impact studies, which can certainly take weeks and months and cost tens of thousands of dollars just for the studies not alone – not even talking about the cost of mitigation strategies if they're required.

Slide 14:
So the most of the major utility concerns are on this slide, and this is coming directly from utilities in the questionnaires we asked. I went back and looked at the results of all the utilities, and I kind of put these in order of what their greatest concerns were. This is really no surprise from all of the discussion that we've had with utilities over the years and with what we know they use in their modeling and their impact studies.

So voltage regulation, protection system coordination, reverse power flow are three of the most common concerns of the utilities. That's three areas that they look at. And of course, increased duty of line regulation equipment is certainly important as well as unintentional islanding concerns, and there are others. Variability, increased switching, secondary network protection.

Slide 15:
This slide shows some of the less common concerns of the utilities, but I wanted to show those nonetheless. And again, these are kind of major and minor concerns.

Certainly, it depends on the employee of the utility and the utility itself, but it's interesting to see where the concerns lie.

Slide 16:
Now as far as detailed impact studies, they follow pretty closely with what those top three concerns were. I show power flow, short circuit, and voltage studies as three of the most common type of impact studies conducted by utilities, and they follow the top three areas of concern. But some of the other impact studies may include feasibility studies and facility studies. Those are typically done upfront just to discuss the project to see that there is utility equipment nearby, what is the feasibility of this project. What needs to happen in order to interconnect this system? And that's probably more important when you start talking about megawatt level scale systems.

Many utilities are looking at quasi-static time series type modeling, but most are not doing those yet. But it's more of a research type modeling platform. Flicker, power

quality, those are also concerns in their study on some of the different software system, but they're not as common as the three in red. Dynamic and transient stability, those are very common at the transmission level for large generator interconnection. But there's some interest. Not very common, but some interest on the distribution side, as well as electromagnetic transient studies. And in the box on the right, you'll see some of the more common softwares that we found that utilities use. Synergy and CymDist are very common among investors on utilities. Mill Soft Windmill is certainly the software of choice for the cooperative utilities, of which we have about 1,000 in the US.

DEW energy work station, ASPEN, and Open DSS are also three other systems that are mentioned. There are a number of software applications out there, and some utilities have their own in house systems, either spreadsheets and worksheets that can help them get through. But these are common software. For the most part, all the utilities said that they used software for their impact studies.

Slide 17:
Now the mitigation strategies, which I know is a big part of the focus today, is listed, and I broke this out as far as the four regions and what the common mitigation strategies are that are used in those areas.

And I think we can see over on the left I went ahead and changed the text to red, just the most common type of mitigation strategies, upgraded line sections, modifications of the protection scheme are two very common strategies. Most of us know that upgraded line sections can be very expensive, while modified protection can be relatively inexpensive for the most part. Voltage regulation devices or modifications of the settings is actually fairly reasonably priced I would say. You're not talking about the high cost of upgrading line sections or adding new feeder lines, but it can be very reasonable in terms of cost or efficacy.

Direct transfer trip is required on certain installations, typically very large systems, and those can be very costly depending on the kind of communication that is used for these systems. There may be some more inexpensive ways to conduct direct transfer trip strategies with power line carrier technologies in the near future, and one utility in the northeast is actually working on some power line carrier systems, and that kind of falls under the communication and control technology area, which had 11 utilities that utilize that, and that also falls into and overlaps with direct transfer trip.

They want to be able to monitor and control especially those larger distributed generation systems. And I don't think it'll be a surprise to anyone on the phone to see the advanced inverters are very high on the list just in terms of strategies, and a number of utilities mention that they're really looking closely at advanced inverters trying to understand how they could deploy those and make those work to improve interconnection and the behavior of distributed generation on the feeders. In California, they get the California Smart Inverter Working Group, and that will likely be integrated into the Rule 21 procedures in California.

Again, especially looking at the larger PV systems.

Some of the others are certainly mitigation strategies that are employed, and there are others that are not on this list, but these are very common across the U.S., and the cost can vary pretty significantly. Grounding transformers is one that's being used in certain regions. Actually, in all four of the regions. But the cost of grounding transformers can be rather high. Re-closers, volt/var bar controls, capacitor modifications, again, not as common, and the price can vary significantly.

Slide 18:
Finally, we've rolled up. I didn't want to call this best practices just because I think there are a lot of practices that are mandated, and utilities don't necessarily have a choice, but there are obviously some more practices amongst the more experienced utilities that could be looked at and considered I think by many of the utilities that are just now rolling out greater and greater amounts of PV and other distributed generation.

So I think it's pretty clear that an open communication between the utility and the PV developer is important for all parties. Online interconnection applications are also very helpful. We found that many of the utilities place their interconnection applications online, and some even had methods to track those systems online, and that's kind of the third bullet, the ease of tracking – ease of tracking project status, and that can be done in certainly a phone call or an e-mail is a great way. Some of the utilities really wanted to stay with that just because of the personal interaction with their customers.

Other utilities have also placed systems online so that a developer, a customer can get on and check the status of a project because there is so much back and forth throughout a project. Using a rational screening approach is also pretty common amongst the experienced utilities so that a developer or a customer kind of knows what they're getting into and what can be looked at when they apply for an interconnection. Supplemental screening options is also very helpful, and the utilities that employed that also stated it helped them to avoid having to go into a detailed impact study. They looked for kind of that safety valve approach to solve the simple problems and avoid the more detailed expensive impact studies.

When you do have to go into an impact study, certainly a standard approach is good so both utility engineers know how that's going to progress and the PV developers know how that's going to happen. Some utilities even allow the developers to get involved in that process and be part of that impact study analysis, and I've got software at the end of that as well. Many of the distribution modeling software packages allow the utility engineers and the various consultants to conduct standard impact studies.

Cost effective mitigation strategies is always appreciated by PV developers. As I said in the last slide, many of the mitigation strategies can be very, very expensive. We looked at one utility last year who had a case study where they looked at approximately five different mitigation strategies for one PD system. The more expensive mitigation strategy was in the $2 million plus range, and the least expensive strategy, which actually

was very effective, was to deploy advanced inverters to control power factor, and the cost of that was just a few thousand dollars. So that mitigation strategy in that particular case was chosen, and it was by far less expensive and appreciated by the PV developer, and it actually had the best impact on the feeder.

Uniform state rules and processes for all utilities is one that I can't emphasize enough. It seemed that the states that had very well thought out rules – and I'll just mention California and New York – other states have good rules as well, but not all states have developed a well thought out – and you know, with experience, these kind of rules and processes. So those states seem to do very well, and the utilities knew what they needed to do. They knew what the timeframes were, the interconnection application process, when they could – when they needed to go through a detailed impact study, et cetera.

And again, overall streamlined and transparent processes were very useful, especially in talking with PV developers. When they know what they're looking for in a particular state, it's better for their business, and they want to do business in that state, and with those utilities, and with the utility customers, and it keeps the cost down for a PV system as well when the process is well understood.

Slide 19:
So with that, I'd just like to say thank you to everyone. That is not me. I haven't lost all my hair, but I'm getting close to that. Anyway, I hope you all have a great afternoon, and thank you very much.

[Speaker: Kristen Ardani]
Slide 20:
Great. That was an informative presentation. We'll be sure to thank Michael Coddington in person when we see him next. I'm just going to take a look and see at our – because we haven't necessarily had any questions roll in yet, so what I would suggest is as questions arise or pop up, please do put them in the Q&A box, and then we'll hold all of the Q&A until the end of Robert's presentation. So with that, I'm going to turn it over to Robert Broderick.

[Speaker: Robert Broderick]
Yes, good morning or good afternoon everyone. As Kristen mentioned, I'm a principle member of technical staff here at Sandia National Labs, so it's my pleasure to be presenting today on the work that we put together to actually look at 100 different impact studies that are part of the small generation interconnection procedure. And this work that we'll be presenting today is supported by the SunShot program run by the Department of Energy. Our specific focus within the SunShot program is on the area of system integration.

So I wish to thank my co-authors on this study, which is Santiago Senna, and also Jimmy Curos, and I look forward to your questions, so please put them in the boxes as Kristen

mentioned, and we'll be happy to address those at the end of the talk. So let's go ahead and begin.

Slide 21:
So first of all, just so everybody is on the same page, what we're looking at here are 100 different impact studies that were part of the small generation interconnection procedure, which is for standard interconnection procedure. This procedure has also been adopted by many other states as part of their interconnection procedures and has recently been updated.

The most recent one that Mike was mentioning came out with a variety of changes to the fast track process, and that's effective as of February 3, 2014. Just to be clear though, all the SGIP studies that we're talking about in this study were under the old rule, so we're not talking about relatively recent studies, rather most of these are about a year old. So the SGIP process refers to interconnecting facilities that are 20 megawatts or less that connect on either the distribution or the transmission system. And there are three evaluation procedures that are built into the S chip process. One is for very small inverters, net energy, metered systems, 10KW or less.

The fast track process, which I mentioned, has recently gone under revision in the latest rule. The old fast track process was a specific threshold of two megawatts was the criteria. If you're greater than two megawatts, you did not qualify for fast track and you went into full study. The new process is more accurate and a much better approach. It's based on voltage class. It's based on how close you are to the substation source, and it's also based on how big of conductor you're connected to. So it's a much better approach that's based on the actual power system characteristics for determining eligibility for fast track process. And then finally, what we're going to be talking about in this study is when you don't need either one of those two processes above, then you go into the full study.

And we're going to be looking at the details of 100 of those studies. So what we did is we canvassed a variety of utilities, gathering data off public websites, specifically Oasis website where utilities put their studies, and we classified the studies by interconnection type, and also by facility cost. We then analyzed the types of adverse impacts that we could find for each of the studies, and also analyze mitigation options and associated costs.

The utilities that we worked with were a variety of different utilities. We ended up with seven distinct utilities, those being P&M Resources here in Albuquerque, Arizona Power in Arizona, Pacific Core, which actually is three different utilities. Pacific Power, Rocky Mountain Power, and Pacific Core Energy, and then we also grabbed some data from PGAM, the regional transmission operator, back in the northeast. And the specific utilities that were in those studies were Jersey Power and Light, Atlantic City Electric, First Energy, and PSE&G. So we have a good cross section of utilities that we gathered data from for these 100 studies. Next slide, please.

Slide 22:
So the 100 data sets ranged from one megawatt to 20 megawatts. The most of the facilities – actually, all the facilities in this study failed the fast track screens. You can see the various screens that are listed there. I won't go through each one of them, but the most common as Mike Coddington mentioned in the previous talk was the 15 percent of peak load on the line section. That's the most common screen that's failed, and it pushes a PV system into the interconnection study. The other ones that you'll see in the graphs relate to whether the system is greater than ten-megawatts or larger. Those are also criteria for doing a full study.

Slide 23:
So what we did as part of our approach was to go through and look at all the different potential interconnection topologies, and what I mean by that is how actually are they interconnecting to the power system. So the first one would be no surprise to most of the utilities on the call. The most common place to interconnect is on the existing distribution circuit. So this in our study range – voltage ranges were from 1247 to 34.5 KV, and this is generally the most cost effective and usually one of the easier approaches because you're not looking at building anything new in order to interconnect.

It's important to know that there are boundaries between the interconnecting facilities as shown on this diagram and the actual facilities of the generator themselves. In looking at the studies, these are important demarcation zones between where costs are determined.

Slide 24:
So the other type of interconnection topology we came across was basically the build new distribution circuit. So in this case in the first example, we're looking at a single feeder where the generator is either large enough or the existing distribution circuit is already saturated, so you're needing to basically build a new feeder circuit off of the bus – low side bus of the substation transformer, assuming that you have the breakers allowed to do that, and that's typically a – something that's determined during a feasibility study that says this is going to be needed to be built in order to accommodate the size of the generator or the fact that the other circuits are already heavily loaded.

The second version of the topology for build new distribution circuit is the double feeder circuit. This happened in a couple of cases where the utility was able to supply part of the generating facility through an existing circuit as shown in the lower left diagram off of Feeder 2, but then we're needing to build additional feeders in order to provide the second generator's resources. In this case, it's actually requiring also that a new substation be built. So as you can imagine, putting that kind of new service in place is generally pretty expensive proposition.

Slide 25:
And then the final or fourth topology that we found was a little bit confusing perhaps, and that is that you're actually interconnecting on the high side of the distribution substation, but you're still connecting to a high voltage distribution circuit. So this would be an example of say something between 69 KV and 25 KV where you've got another

substation transformer further upstream that's actually connecting to transmission voltage, such as 115 KV. This is a very common interconnection process for large PV systems, specifically 20 megawatt, and larger systems are generally connecting to this high voltage DC bus that's on the high side of the distribution transformer.

Slide 26:
So what we're looking at now going into some of the details of the study that we looked at – as I mentioned, we have four major utilities that we looked at. The PJM one has the four other utilities that I mentioned built into it, and what this slide is showing is the range of PV systems seeking to interconnect. That's along the X-axis, so that's the megawatts of these facilities, and then along the Y-axis, we're looking at the number of facilities by utility. So in this case, you can see a lot of red over in the two to three megawatt range. This is – sorry, I got a delay on my screen here. Hold on just a second.

Okay, I'm back. The red off to the left you can see is a lot of Pacific Core systems. They have a lot of the smaller systems where off to the right, you can see some of the bigger systems are on the APS system. So what we're trying to show here is just the spread of different facility sizes for each of the utilities that were part of the study. It's important to note that a lot of the megawatts that installed up to seven megawatts or 66 percent or less of the total facility sizes, and that we're getting over 82 percent of the studies were 11 megawatts or less.

So we've got a lot of action on the ten megawatt and less size – number of smaller systems on the larger size.

Slide 27:
So we also looked at the general statistics by voltage class. No surprise we're seeing most of the interconnection requests are the most common distribution voltage, the 1247 KV. But you can also see we've got a tail function out here on the right hand side that we've got a lot of systems that are connecting at the higher distribution voltage. As I mentioned, this is typically on the high side of the distribution transformer, 34.5 KV and 69 KV in the system.

So roughly 70 percent of them were at 1247, and all of the 20 megawatt systems that sought interconnection were 69 KV.

Slide 28:
So what we're looking at here is the interconnection topology versus facility size. And it's worth noting in here that when you look at the greens – the tap existing low, which as we mentioned, is the low distribution – the low voltage side of the distribution transformer, you're seeing that almost all of those are ten megawatts or less. And when you look at wherever you've got tap existing the high voltage distribution circuit, with the exception of one of them at 13 megawatts, all of them were at 20 megawatts, and then you've got build new spread pretty much throughout the entire range of values there.

So it just gives you a good first impression on how the megawatt size is related to the topology of interconnection.

Slide 29:
So what we did is we looked at all the different possible effects that were listed in the studies, and starting with the tap existing distribution circuit, we found that of the 78 studies that we looked at that related to that specific topology, 53 of them, or 68 percent, identified adverse impacts, but 25 of those studies did not, or the other 32 percent. So it's really worth noting that this is indicating we could do a lot better on our potential screening process that we ended up with that many studies that were thought to be a problem, but at the end of the day when the study was done, there was no adverse impact determined.

It gets even more lopsided when you look at the results of doing a study after a feasibility study has been done, and you determine that you're already going to build new distribution circuit, and then you still have to run the study. We found that 86 percent of those in that situation, 86 percent of them or 18 studies had no adverse impact at all. So when you combine that all together, you're ending up with a situation with approximately 44 percent of the – sorry, 44 – yeah, 44 percent of the studies that we looked at were required to go into study, but actually identified no adverse impacts. So once again, this really indicates that there is better work we can do with our initial screening process and make it a more accurate process to really identify those interconnection requests that have actually high potential probability of causing adverse impacts.

Slide 30:
So we went and looked through each of the impacts and determined really what was the cause of the impact, and as you can see, the dominant form of, at least for these 100 studies, were protection impacts. Forty-three of the studies have some form of protection impact. The voltage impacts, which we were actually expecting to be the dominant type, were still significant. Twenty-nine of them, of which 19 were over voltage, and ten of them were voltage deviations, and then thermal impacts occurred, but they always occurred in conjunction with some other issue on circuit.

So what I think the main takeaway here is it's really important that we focus our efforts as much on protection issues as we do on voltage issues in terms of doing our impact studies.

Slide 31:
Okay, so now we're going to get into actually looking at how the costs for mitigating the interconnection were handled for each of the different types, so we're going to start with over voltage, and then we're going to go into voltage deviation, then look at thermal, then look at protection. So what we're talking about here for over voltage is the case where the PV is indeed injecting current into the circuit, and it's causing a voltage rise that's causing the voltage on the circuit to exceed the ANC range age specification.

And as you can see in this graph, what we're plotting along the X axis is the various megawatt sized systems that saw an interconnection that actually had over voltage issues, and then what we're plotting along the Y axis is the total interconnection costs. And so what you're seeing in red is the percent of the cost associated specifically with addressing over voltage mitigation. And as you can see, there's a lot of zero costs associated with these systems between four and ten megawatts right in the middle of the graph.

Those costs were zero because the very cost effective mitigation strategy was put in place, and that was to set the inverter power factor at a lagging power factor, which solved the voltage rise problems very cost effectively. You can also see that over in the two to three megawatt range on the left side of the graph, you're getting a wide variation and total interconnection cost between six percent of interconnection costs up to 24 percent of interconnection costs. So what this tells us is that even though they're small systems, it really depends on the location in the specific circuit parameters that they're connecting to, are determining what the costs are.

So the range of cost, just to give you some percentages, the range in cost were entered from zero cost when you did power factor correction, up to a maximum value of about 380 K of cost to mitigate that over voltage.

Slide 32:
So now we're going to look at voltage deviation. So what we mean by voltage deviation is a percent voltage change that's being caused by the variable PV output. This could be something as simple as cloud cover coming across, and the best analogy for this in terms of the thinking of voltage deviation is, for example, the voltage change that's required for motor start on the distribution circuit. That's why these percent voltage changes are built into the system in order to ensure power quality and power reliability.

So we found that the voltage deviation was actually very expensive to mitigate. As you can see in the note below, the range of values was anywhere from 400 K up to five million dollars to mitigate these over voltage issues that a lot of the equipment is being used for that, can be some of the more cost effective things such as voltage regulators, conductor upgrades getting more expensive, and the five million dollar cost was associated with a static bar compensator that was required.

So it's worthwhile to note that the voltage deviation had one of the greatest percentages of interconnection costs and also had some of the largest values we found in the study. Also, it's important to note that these voltage deviations range across the whole gamut of facility sizes as shown here from two to 20 megawatts, so it's not something that's just associated with the large PV systems.

Slide 33:
So now we're looking at thermal impacts. The variation here was between two and ten megawatts of the facility sizes. We didn't see any thermal issues that showed up in the larger sizes primarily because as we'll show later, those were being served by building

new circuits, but in this case, you can see that the thermal variation really varies evenly across the various sizes. You can get very large percentages, such as the three megawatts for 72 percent of the interconnection cost is associated with conductor upgrades, for example.

So thermal impacts generally are more widespread than the other impacts we looked at.

Slide 34:
So now we're going to go into discussing the protection impacts that Mike mentioned in his presentation are often the very, very common source of mitigation and mitigation costs. We're going to look at both the substation and also look at the distribution system. So starting with the substation, we can see that there are, once again, a wide variation across the sizes, anywhere from two to 20 megawatts, and you can see that the cost can range from a very small amount, such as just simply adjusting the relay settings, which is one percent of the cost, all the way up to installing new protective relaying in say an old substation which is going to run in the millions of dollars.

So wide range of possible values for protection mitigation cost for substation relay modifications.

Slide 35:
So now looking at the distribution system, not as wide a range of facility sizes associated with distribution upgrades, looking from two to nine megawatts. But it is important to note that you're once again seeing a big variation of what the percentage of cost is, anywhere from 11 percent up to 69 percent of costs. It's also noteworthy that these costs are significantly less than what we had before under the substation cost where your highest cost is 178,000 in this case. So definitely the distribution protection stuff is much cheaper to solve than it is at the substation. You solve by a dollar amount.

Slide 36:
So now we're going to get into the total cost analysis by looking at how these facilities are installed on the various topologies. So the thing to note here is that for systems that are smaller than 20 megawatts, you can see that generally tapping the existing circuit is one of the less expensive options. You can see that also as you get into the 20-megawatt or larger systems that there's a wide degree of variation. Sometimes it's less expensive to tap existing, which is the green triangles, or build new, which is the blue diamonds. That variation that you're seeing over at the 20-megawatt level is no doubt driven by location and site specific situations.

For example, having to build less distance versus having to do various upgrades for tapping the existing high voltage distribution circuit. So we get a fair bit of variation out on the 20-megawatt level, but for the rest of it, you can see a fairly consistent pattern here that certainly the more cost effective approach is generally the tap existing low, and then as you get into the bigger sizes greater than ten megawatts, you're looking at – sorry, I have another delay on my screen here. My apologies.

You can see that you're getting the facility sizes less than ten megawatts primarily tapping existing low. And the cost range for the overall interconnection cost was anywhere from $22,000.00 up to 11 million, and this is really I think interesting data to look at, but I think what's more interesting to look at is what the cost is per megawatt.

Slide 37:
So let's go on and go onto the next screen. So this is what we ended up doing for this is actually doing the cost analysis, same by topology, but now looking at what the total cost is per megawatt, and you can see a pretty straightforward trend here where we're looking at the small size PV systems are generally more expensive to interconnect per megawatt, and you're also seeing, once again, the same trend that building new is generally more expensive than tapping existing.

Once you get out to the 20-megawatt level, you can see that they're more cost effective simply because you're spreading your costs across a larger number of megawatts. So the main takeaway from this is that certainly it's more cost effective from an integration perspective to put in larger systems. However, the downside of putting in larger systems is that generally, the studies are taking a longer period of time, and there's increased risks associated with whether you're going to be able to tap an existing circuit or whether you're going to have to build new, and the time it takes to build that new service.

Slide 38:
So the final slide that we have in terms of doing the cost analysis was just to see if we could determine any trends for looking at how the interconnection cost varies by voltage class, and as you can see, there really isn't much of a trend here at the 1247. You're getting a wide, huge range of total interconnection costs at 1247. You're getting also a similarly wide range of 69 KV. So our general conclusion from this was that since it's such a site specific interconnection scenario that looking strictly at voltage class to get an idea of how your interconnection costs are going to vary is probably not the best idea going forward.

Rather, it's better to look at your megawatt threshold and look at which topology you're interconnecting to is your better approach for getting a first sense or a first cut at what your costs are going to be.

Slide 439:
So our overall conclusions from doing this analysis of the 100 different studies is that the interconnection topologies were strongly correlated to the presence or absence of adverse impacts. That indeed, the protection impacts were the most common, identified in 43 percent of the cases. We found that the over voltage impacts were generally the easiest and the least costly to mitigate with over half of them requiring no additional cost. That was making use of the power factor correction.

We found that voltage deviation impacts were overall one of the most difficult and costly to solve, and finally, the work that we're continuing to do at Sandia is to work on improving these interconnection screens so that we don't have as many false positives that come through and to work on determining increasingly cost effective mitigation strategies for common impacts, such as using advanced inverters.

Slide 40:
So with that, take next slide please. So if you have any questions we can't answer today during the call, feel free to e-mail me or my co-author, Jimmy Curos, and we'd be happy to answer your questions, and the data that I've presented today is in the following Sand report which is available on the Sandia website.

So with that, I'd be happy to take questions.

[Speaker: Kristen Ardani]
Slide 41:
Great. Thank you so much, Robert. Yeah, definitely a lot of the underlying data is available, so we encourage folks to actually pick up the paper. I found it really, really informative to see how all the different topologies and whatnot were categorized. At any rate, I want to turn over to a few questions. There were several questions, Robert, around the sort of protection system impact, and kind of what were some of the most common protection system impacts identified, and how were they mitigated? What are some common forms of mitigation for protection impact?

[Speaker: Robert Broderick]
So the most common problem that occurred, at least at the substation, was figuring out how you're going to handle reverse power or other issues related to the protection coordination. So that was the most common and the most expensive was to do that at the substation, and the most common solution was simply to go through and change the settings, but often times, that wasn't as easy to do as one would like. So you actually then had to implement more advanced relaying functions, such as deadline checking, direct transfer trip, and in the worst case scenario, you actually had situations where you had to install new protective relaying in the substation, and that was the most expensive option.

[Speaker: Kristen Ardani]
Great. Thank you. So the next question we received is when using a power factor to resolve voltage issues, is a utility compensated, or rather is the customer charged for providing the VAR to the PV generator?

[Speaker: Robert Broderick]
So typically, this was the most common utility that did this was APS, and the APS was basically as part of their interconnection procedure and part of their study were basically saying that the connecting system would have to be at a certain power factor that they would operate at, and that basically solved the voltage rise problem. So I guess to answer

the question, the utilities mandating that as part of the solution and the customer is having to basically come up with that var capability when potentially they could have real power production if their inverters are not over sized. So the trade off there is they're providing var where they could be potentially providing real power.

So in essence, the customer is taking a slight hit in their power production by needing to provide var. That's all dependent on the size of the PV inverters. If the PV inverters are over sized such that they can provide that var capability, then basically they're able to provide that impact without any loss of revenue.

[Speaker: Kristen Ardani]
Interesting. Also, so you describe that your data from the 100 studies came from seven utilities, but how did you pick each of those utilities?

[Speaker: Robert Broderick]
Yeah, so this is where I think there is a lot of future work that could be done. Our ability to gather data was the primary constraint, so we were as I mentioned going through the Oasis website, which is their public website that utilities are publishing data, and not all utilities are publishing their impact studies, which I think would be really wonderful if we could achieve that as a common good that everybody would publish their studies so everyone would benefit from understanding what other utilities are doing.

So the ones we were able to gather and put part of the study were the ones that we were first able to find the Oasis website. And then we had to make a decision. There is a lot of old, old studies that had been done, so we picked studies that were done within the last couple of years. So there wasn't really a systematic process beyond knowing that we wanted to grab stuff from across the country and not just all say in the Southwest. And we were able to pretty much cover three regions - the northwest, the northeast, and the southwest.

Not so much from the southern part of the country. We weren't able to find specific studies being released by utilities in those areas.

[Speaker: Kristen Ardani]
So we have time for maybe just one last question, and this question is around the confidence in the four interconnection topologies that you have defined, and whether you've defined those in a way that will capture the bulk of future interconnection topologies.

[Speaker: Robert Broderick]
Yeah, so certainly I think there is a risk there that there's a topology out there that we haven't seen that's kind of an outlier, but I do think that the four we've identified cover the vast majority of what we expect to be interconnected and how they're going to interconnect. I think the one exception to that might be that as net energy metered systems become a bigger and bigger percentage and start causing issues as they are out in Hawaii, we may need to be looking at a specific topology that shows not just connecting

at the distribution – low side of the distribution transformer, but also connecting at the low side of the service transformer as another topology for modeling what's going on with net energy metered systems that are obviously behind the meter at the residence.

So that might be one additional topology we could take a look at as we start getting into those unique cases where there is an impact study that's required for a very small PV system.

[Speaker: Kristen Ardani]
Okay, so we are out of time. I just want to say thank you very much, Robert Broderick, for participating and sharing your data findings with us today, and also thank you to Michael Coddington for pre-recording his presentation for us in advance, and also thank you to everyone for participating and listening in. At this link, you can find the DGIC webpage, and on that webpage, we'll be posting the registration for the next webinar with our speakers from Salt River Project and NV Energy. We'll be discussing screening procedures and online interconnection tools, so I encourage everyone to pre-register in advance through the website, and again, thank you very much, and we look forward to the presentation next month. Thank you.

[End of Audio]