[Speaker: Kristen Ardani]

Cover Slide: Thank you everyone for joining us today for the DG Interconnection Collaborative informational webinar. Today we have speakers from Arizona Public Service Company, who will share their insights of Lessons Learned with Early PV Plant Integration.

Slide 2: Now I'd like to go ahead and introduce our speakers for today's presentation. We will start with Elsa Gonzales. Elsa is a distribution operations engineer at Arizona Public Service, and a recent graduate of APS's two-year rotational engineer program. She holds a bachelor's of science degree in electrical engineering from Arizona State University, where she studied semiconductor device physics with an emphasis in photovoltaics.

Next, we will hear from Rachel Sall who has been in the electric utility industry for five years – two and a half years with Consumers Energy in Michigan, and two and a half years with APS. She has a bachelor's degree in electrical engineering, and master's degree in business administration – both from Western Michigan University. Rachel's general focus has been in distribution, with functions such as planning, operations, overhead, and underground design and mapping.

We also have Frankie Greco. He is with APS's distribution interconnection team, where he has spent the last four of his ten years with the company. He has held various positions within APS in distribution, design and construction, project management, distribution planning, and distribution operations. Overall, Frankie has 13 years of electric utility industry experience, and holds a bachelor's degree in electrical engineering from Arizona State University.

And then we also have David Narang. David is a senior engineer at Arizona Public Service Company in the technology assessment and interconnections group. His overall role is to support the integration of solar into utility operation. For the past four years, David's focus has been to lead a team funded by the Department of Energy to study the high penetration of photovoltaics, established through an APS project in Flagstaff, Arizona. David holds a bachelor's in electronics engineering technology from DeVry Institute of Technology.

Slide 3: So, with that, I will turn it over to Elsa Gonzales. Elsa…

[Speaker: Elsa Gonzales]

Slide 4: Thank you. First of all, I'd like to thank you for taking time out of your guys' busy schedule to join us today to take a look into how Arizona Public Service accounts for distributed generation on its system. In this presentation, we will start off with an introduction of APS's utility territory and energy portfolio, and will then dive deeper into how our distribution planning and operations department analyzes, forecasts, and accounts for distributed generation on the grid. We will also take a closer look as to what APS's interconnection requirements are, and what are lessons we, as an organization, have learned with Power Point integration, as well as what are the tools and capabilities for the integration of distributed generation.

Slide 5: APS is proud to be the largest utility in Arizona, covering almost 35,000 square miles of service territory, and providing reliable power to over one million customers statewide. APS is not only an energy provider, but also generates and transmits power for the Western Interconnection System. We have 28,000 distribution miles, 5,300 transmission miles, and 410 substations. In addition to the load we serve within the state, APS also has a presidential permit to serve an interconnection point in Sunlease Vio Cocreole, Mexico, where we serve several industrial customers on the Mexican side of the border. Currently, we have more megawatts of capacity than our peak demand. With our demand expected to double in the next 20 years, APS is strategically planning our energy resources to meet and exceed that demand.

Slide 6: So here's a little look at APS's energy portfolio. In 2014, as you can see, 83 percent of our generation was met by traditional methods, such as nuclear, coal, and gas, and 17 percent of that generation was met by renewable and improved energy efficiency. In 2029, what we're projecting is that 79 percent of our generation will be met by traditional methods – so that's a 12 percent decrease as to what we currently have right now – and we will increase our generation by renewable and improved energy efficiency to 29 percent. 52 percent of our growth in the next 15 years is to be met by clean resources. So clean resources, as we define them, are wind, solar, geothermal, pump hydro, etcetera.

Slide 7: The renewable portfolio standard is a standard that mandates that by 2015, 5 percent of APS's retail sales will be from solar, and by 2025, that percent is to increase to 15 percent. Of these percentages, at least 30 percent must be from distributed generation – so residential and non-residential customers like schools, industrial, commercial customers are to account for at least 30 percent of our distributed generation. At 925 megawatts currently in 2013, APS's PV portfolio is twice the minimum requirement by the RPS, which means we're not only on track, but we've exceeded the minimum expectations. And just a note – not long ago, we were measuring PV installations in kilowatts. So we've currently grown, I mean, to megawatts and almost 1,000 megawatts this year.

Slide 8: We recently did a study in 2013 to trend a trajectory of what we project our distributed PV to look like, and if you can – as you can see, currently, we are – our current trajectory for 2025 is to have about 1,900 megawatts, and about almost 200,000 customers. We could have as much as 3,500 megawatts and 250,000 customers, but what we have projected currently is right around that 2,000 – 200,000 customers mark.

Slide 9: At this time, I'd like to pass this over to Rachel Sall, as this ends the introduction and this marks the beginning of the distribution planning and operations segment of our presentation.

[Speaker: Rachel Sall]

Slide 10: Thank you, Elsa. Good morning, everybody. I'm going to give an overview on distribution planning and operations. The agenda topics will be distribution feeder peak analysis, distribution forecasting, accounting for distributed generation – how we currently do that – and accounting for distributed generation in the future. Okay.

Slide 11: So from an operations perspective, distribution engineers gather 15 minute data from our EMS pi-historian portal for every feeder and transformer on the system for the previous load year. The year is defined as November 1st to October 31st. So therefore last year's peak for 2013 occurred between November 1st, 2012 and October 31st of 2013. So the operations engineer must find the peak for each month for every feeder and transformer, and then break those down to the peaks for the load year. Because they keep track of the previous three years of peaks for each theater and transformer, we are able to compare past loads to the current year. This serves as a red flag for loads that are much larger than expected under normal growth patterns. If the load is much higher than expected, it is usually attributed to two main things – either a large customer or development came into the area, or switching occurred on the feeder, causing additional load to be temporarily added.

Slide 12: So this graph is an example of switching. To account for switching, we acknowledged feeder high points to determine which feeders could potentially be utilized for switching. From there will pull the data for that day or days with the feeder in question, and available tie-feeders. We are able to notice a quick change in load. In the picture, the blue feeder may be approaching overload, so approximately three megawatts was transferred to the green feeder. To account for large customer development, this typically would be caught ahead of time from communications with our local representatives for new customers, and be accounted for in the planning engineer's forecast. Therefore, when the variance exists, we are able to explain it. In addition to accuracy, accounting for switching helps from double counting a specific amount of load on two different feeder peaks.

Slide 13: In terms of forecasting, planning engineers take multiple things into account. New work orders, keeping in mind, "Will the customer be in service by the peak of the following year?" New customer loads that do not have a work order generated – and that's usually through the local representative. What part of the state a feeder falls within – this could impact the KW per home when the planning engineer uses this to forecast out of the division, or the rate of lots to be sold in a certain area. In addition, we consider past growth in the area and any business load that may be leaving the area. Distribution feeders are forecasted for four years, and distribution transformers are forecasted for ten years.

Slide 14: So considering the peak load, any new load, and any forecasted megawatts or percent growth, planning engineers determine if an overload exists on a feeder. So then what if there is not enough capacity on a feeder or transformer? Assuming load is correctly balanced, power factor is good, and ties-points have been utilized, a capacity project will be necessary. Projects such as building a new substation or building a new distribution line will be considered. When vetting alternatives, a risk analysis is done by considering what will happen if the project is not performed, as well as schedule and budget constraints that need to be adhered to.

Slide 15: So prior to 2013, peaks were accounted for by one peak value, typically reverse peaks were not gathered unless it was a dedicated distributed generation feeder. This past year, we added peak values to account for. We gathered maximum forward, maximum reverse, calculated forward with no DG, and maximum DG. So some definitions. Maximum forward is defined as the maximum forward peak including DG. Maximum reverse is the maximum reverse peak including DG. Maximum calculated forward with no DG is defined as the forward peak that does not include the DG. And maximum DG is the max DG on the feeder or transformer. Gathering and tracking multiple data values as indicated above allows us to analyze transformers with a load feeder and a dedicated solar feeder to account for maximum forward or reverse flow compared to the rating. The graphs that follow indicate some of these scenarios.

Slide 16: So this first graph indicates a peak for a feeder with no DG. For feeders that have no DG, the blue line indicated comes directly from our pi-historian portal, where we gather our peaks. So maximum forward peak and the maximum forward calculated with no DG would equal the same thing, because there is no DG, and the maximum reverse and maximum DG are zero.

Slide 17: So this graph displays a feeder with some DG, but not enough to cause a reverse flow. So there's multiple lines in this one. The red line is now the data that comes directly from our historian portal. The green lines can come now if it is a dedicated DG feeder, but in the future, we would like to gather this data for low feeders that contain DG – so such as feeders that would contain rooftop solar. The blue line is the calculated maximum forward with no DG. It does not currently track for low feeders with DG, but where we want to be in the future. So the DG on this feeder transformer exists, but is not great enough to cause a reverse peak on the feeder or transformer.

Slide 18: So this graph indicates a forward peak with reverse flow. The lines indicate the same thing as indicated by the key. The line differs as it has more DG, bringing the red line down and actually causing a reverse peak. It's not higher than the forward peak, but it's still causing reverse flow. And if you're only tracking the red line, you may actually miss the feeder transformer peak by the maximum forward blue line. So that's what we want to make sure we don't miss in the future.

Slide 19: The last graph indicates an actual reverse peak that is higher than forward – so the DG is even higher than it was in the previous two graphs, carrying the maximum reverse peak down further. The reverse peak is actually higher than the forward peak. So the main point we want to keep in mind is that the load on a feeder, if there is no DG such as rooftop solar, what is that load?

Only considering the red line may give us a false picture of the feeder peak load. Additionally, what is the maximum DG on a feeder or a transformer? We want to ensure – although potentially unlikely – that if we were to lose all the load on a feeder or all the DG that we wouldn't be overloading any of our equipment.

Slide 20: So for the future we are looking to utilize a renewable feeder tool, and this tool allows us to capture how much DG there is on a load feeder, as opposed to only being able to capture dedicated DG feeders. We will need to ensure that not only are we capturing the maximum DG on a feeder, but that we are lining up the actual amount of DG at a specific time for the feeder to calculate our maximum. We will also like to utilize feeder DG forecasting and visualization tools to determine the amount and impact of DG on a distribution feeder. So this presentation has been more from the planning side, and Dave will talk more later about the operations, and next we have Frankie Greco talking about interconnection requirements.

[Speaker: Frankie Greco]

All right. Thanks, Rachel and Elsa. Appreciate your input here.

Slide 21: Okay, so, again, I'm Frankie Greco, senior interconnection engineer. Here's the agenda that we're going to talk about today, my segment, anyway: Rooftop solar installation numbers, summary of the interconnection operation, standard APS interconnection requirements, lessons learned for the last five years, and some future challenges.

Slide 22: All right. So this slide represents our residential numbers for the last eight years. We had 9,000 applications received in 2013 for residential, and had about 200 commercial applications. The interconnection team, the folks that I work with, is made up of a group of engineers, analysts, and inspectors, and project managers – a total of nine folks dedicated to interconnection full time.

Slide 23: All right. So this, basically, anybody who wants to interconnect with APS is going to do so with one of three options, one of three modes, basically. You've got your continuing parallel, which is 95 percent of all projects who fall into that category, whether it's PV, wind, geothermal, hydro, biogas – or you might have smooth parallel transition or momentary parallel transition. Smooth and momentary parallel transition modes are for emergency backup generation only. Customers wishing to interconnect these systems with APS will be subject to additional requirements.

Slide 24: Okay. So let's talk. We're going to talk a little bit about some of the key components that we require for interconnection. We require utility disconnect switch – this is not an NEC requirement, however APS feels it is necessary for the safety of APS and the general public that the disconnection switch can be used as a clearance point to isolate APS from the customer's generating facility or GF. The disconnect switch shall be lockable with an APS standard issue padlock, shall be installed for APS elevation and workspace requirements, and if not within 10 feet of the service entrance section, shall have a warning sign with directions at the SCS as disconnect switch's location.

Slide 25: The disconnect switch shall be the visual open design, with the cover open, i.e. blades, jaws, and air gap. If arc shields are installed, shall not impede APS's ability to verify our visual open requirement, with the front cover open. The disconnect switch is placed under APS operational jurisdiction for voltage class 600 volts and less. For greater than 600 volts, an operating agreement is required.

Slide 26: So we're going to talk about production metering now. All generating facilities that back feed the grid for renewable energy credits shall install a ring-tie production meter. APS metering shall be in accordance with the APS electric service requirements manual, and we'll give the web address at the end of the presentation as to where that's located at. For indoor applications, our lower elevation, which is printed there on the slide, changes to 36 inch minimum, however there are very few metering installations indoors for PV. Those that are indoors are mainly commercial and industrial applications. For any all-CT rated metering, APS will install the CTs for installations greater than 200 amp. For 12 KV primary, APS will install CTs and PTs. All primary applications shall include grounding provisions. APS has installed or plans on installing AMI metering devices throughout the APS system in order to capture the production of most of the generating facilities installed, and that's key to help our operations and planning engineers like Rachel and Elsa get a better idea as to how much PV is on the system during our feeder and system peak.

Slide 27: All right. So I'm going to talk to you a little bit about readily accessible – utility disconnect switch and production metering enclosure shall be installed in readily accessible locations. And by 'readily accessible', it's defined as by APS including reaching quickly and conveniently on a 24 hour basis without requiring climbing over or removing obstacles, obtaining special permission keys or security clearances. Equipment cannot be located behind a gate, fence, or wall, or other barrier, unless expressly agreed to by APS. Lockboxes may be required if the customer wishes to limit access to set equipment. Normally commercial applications, we would only allow this for. Indoor equipment locations require access from the exterior of the building. We can't be walking through a main entrance, lobby, corridor, hallway to get to an equipment room. We have to be able to walk to the outside of the building to a meter door or room that limits access from the interior of the building. So it's got a door inside the meter room to the interior of the building. It has to be locked and we cannot have access to it. APS has allowed a security escort provision in the event customer's operation is of a sensitive nature. High security, data center, government building, prison, courthouse.

Slide 28: Okay. Let's talk. I'm going to talk to you a little bit about our study process. Pretty high level. So APS requires a study to be done for any project one megawatt and larger. APS schedule six outlines three study options: feasibility, system impact, and facilities. Schedule six applies to any GF interconnected at 59 KV and less, with the sole purpose of selling generation to APS, and not subject to FERC interconnection rules. Additionally, retail customers interconnecting behind a retail meter are not subject to schedule six, but are still required to go through a facilities study process.

Slide 29: Okay. So a couple of high points with this with this slide study. The study process takes 90 to 120 days, depending on complexity. Many of the same folks assist with multiple other efforts, and are not dedicated to just interconnection. That's the reason for the timeframe. And 'behind the meter' is APS jargon for a customer that has retail load and wishes to install a generating facility behind their retail rate metering point. So you could have a target store, for example, and they want to put a one megawatt system on their roof. So those types of folks would be put through a facilities study process. They'll be given an estimate, but they also have retail load type deal. So they would more likely want to go on a net metering type rate. And then lastly all interconnection projects not subject to FERC rules will go through an estimate at project completion. Basically, we will estimate the cost to that customer, upfront, provide them a full-blown estimate. They'll sign an interconnection study agreement, they'll pay their fees upfront, we'll build a project, and then at project completion, we'll do a true-up. We'll see how much money we actually spent. If it's above and beyond in excess of what we initially estimated, the customer will be charged the difference. If we came in under budget, that customer will get that advance.

Slide 30: All right. So I'm going to talk to you folks a little bit about remote disconnect for one megawatt and larger. Basically anything that's one megawatt and larger that back feed the grid for the sole purposes of net metering or selling generation to APS will be required to have remote monitoring and remote disconnect capability via an RTU or Remote Terminal Unit. It was decided to implement this requirement back at the end of 2009, when we interconnected our first one megawatt solar system, located behind a retail rate customer service at 277-480 volts. APS operations shall have remote control over the customer's generation or main breaker, via breaker control scheme. Customer shall secure and pay for the communication path. A com-path shall be either a VG36 or fiber, depending on what may be available in the area that the customer is interconnecting. And it was decided to use one megawatt as a minimum as powers traded in one megawatt blocks – our portfolio management folks were and are interested in capturing how much of our energy mix comes from renewables. It's another reason why.

Slide 31: I apologize. We went dark in our building, so I can still read the slides, but bear with us. Okay. So moving on. APS provides RTU equipment for all projects requiring it. Customer is responsible for installing power circuits, any cabinets, enclosures, and racks. So one of the items worth mentioning here is APS has installed over 32 sites within the last five years, one megawatt and larger, with remote disconnects, and monitoring capabilities. Some of the pictures that I've shown you on the screen – the picture on the right is a small RTU that we would install at a one megawatt or larger rooftop solar retail customer type installation. The picture in the bottom center is some com equipment, com racks that you might see for maybe a large scale utility solar type application. They are all different, the utility scale. And so are the behind the meter retail rate customers. Those are some samples of what you might see.

Slide 32: All right. So I'm going to talk to you a little bit about our dedicated feeder requirements. Dedicated – for dedicated feeders, any generating facility that is one half of our standard APS load feeder, which could be 13 megawatts in metro-Phoenix, or 10 megawatts or less in our state-rural areas, is required to have a dedicated feeder. We may require dedicated feeders or dedicated

APS for less than one megawatt, depending on the technology. For example, we had a situation last year where we installed a dedicated TAP for a biogas plant. They just – they had some spinning mass. They were 600 KW. They were installing two of them. But as most of you folks know that are on the phone, when you shut down – when you have an operation at a breaker at a substation, and it's spinning mass, that spinning mass doesn't have anti-islanding technology built in. So we incorporated a transport trip scheme where if we open, they open. And basically to keep ourselves safe, our workers safe, and the customer safe. All dedicated generation feeders will have direct transfer trip capability. So basically something that's 10 megawatts and larger or so – an engineering study could be system impact, high pen modeling, or other factors. We make reference in there about the DG penetration limits of the distribution feeder will be exceeded, could be exceeded, based on the results of an engineering study. That might be a trigger to do a dedicated feeder.

Slide 33: All right. So let's talk – I'm going to talk to you about advanced grid support features, which we've recently implemented. Anything that's 10 megawatts and larger shall offer voltage control capabilities and modes at the point of interconnection. These modes, dynamic response requirements is what we call them, and it's located in section 8.9 of the APS interconnection requirements. Basically, we have – the modes that we have to offer or we want implemented, rather, are power factor control, reactive control, and automatic voltage regulating control. APS requires an eight second response time between step changes and mode changes, VARs at night may be utilized in the future to support the grid. You might have a situation where if it's an irrigation feeder, an irrigation area, or heavy industrial, those types of systems might require – those types of areas, rather, may need VARs at night to help support the grid. Voltage and frequency rise through capabilities shall be activated if the system supports – if the system requires it, and the system that customer's installing – maybe it's SMA technology or some other inverter – smart inverter technology, and they have that capability, and it's just a simple push of a button to activate it. All right. And then, lastly on the slide, APS transmission ops engineering shall determine the best mode of operations for the utility scale plant. Our standard mode is 0.98 leaning power factor, absorbing VARs at the generating facility.

Slide 34: All right. So here's some of the information you're going to want to know about lessons learned the last five years. Okay. So, basically, several bullet points. Sites requiring communication and control shelters are best served via a separate single-phase circuit via separate feeder. Those, and the reason for it, okay, you've got a communication control shelter that shares the service that's brought in to feed the entire solar plant or to back feed the entire solar plant. We lose our breaker at the substation, we open the breaker at the solar plant, and the whole com shelter goes dark. Best if we have a separate circuit off of a separate feeder feeding that com shelter. Systems with power link controller communication latency has been an issue with previous projects. Also, controller technology is lacking. I'm going to address that second piece here.

Controller technology really hasn't caught up with the rest of the industry. We find a lot of system crashes, software glitches, software bugs with some of the equipment that we've required. Any of the APS-owned plants. So, you know. Developing a more robust plant controller is probably something we need to look at in the future, at least the industry does. As far as latency – well, we had a couple of plants in which we required a specific modes – I'll use voltage control, for example. And one of the plants we installed several years ago, when we introduced this requirement, it took the plant 15 minutes to respond to a step change input, which is absolutely unacceptable, and, in my opinion, doesn't qualify that system to be a dynamic response.

Next bullet point, about dropout testing. It's been difficult to, early on, to simulate dropout testing with APS-owned equipment, metering, voltage recorders, and such, so we put the requirement on the customer to provide us a simulation test report during a plant dropout test. I want to see a sin-wave, a T equal zero, and it shows me the number of cycles it takes for the plant to shut down. It's something that we require with any commercial industrial plant. We want to see a dropout test. Any large scale PV or commercial rooftop PV.

Slide 35: Pictures that I'm showing here. I have a story behind them. So clarifying the type of switch gear – open air versus metal clad upfront. We require for all utility scale plants that are interconnected to the APS system, 12 KV and lower, have to have metal clad switch gear. We had a situation early on in which we allowed an open air switch gear installation, which is something that's just – our people on the distribution side of the business are just not familiar with working on. So we had to accept it and we came up with some safe practices for that plant, but going forward nothing will be open air. It's all going to be metal clad switch gear.

And then the second bullet on this slide, clarifying the number of metering points required in following up with customer shop drawings – submittal prior to equipment installation. Basically, any system that has – that's one megawatt or larger that back feeds the grid has to have two metering points. One meter is your billing meter. That second meter is our EMS meter. That EMS meter captures the production of the plant and sends it to our energy management system, our pi-historian system. And it's something that can be missed. It's a little bit off an oddball situation. Anybody like rooftop solar that wants to put one megawatt, in many cases, they're retrofitting their existing service entrance section to accommodate that second meter. In most cases, the large plants are of medium voltage class, 12-4-77.2 KV. But in some cases, we have a situation where it's secondary service – 2-77-480 or 122-08.

Slide 36: All right. So with a lot of the utility scale one megawatt type plants, we developed a communication control template to provide our customers. The reason we came up with this template – we're not designing customer systems for them. What we're doing is we're providing a template showing all the minimum items that APS needs from com circuitry to breaker control circuitry, fiber optic equipment, RTUs, racks, power circuits, etcetera.

Slide 37: The template basically tells a story of what APS needs, but it doesn't give the customer any information on how to design their system, although there may be some typical items that they may want to install and look at. But we came up with this template because there's lots of confusion as to what conduits APS needs to install, or what the customer needs to install in order to provide us the information we need from a tracking perspective, capturing the production, having remote control of the customer's breaker, etcetera.

Slide 38: All right. So this is the last slide on lessons learned. A couple of these points came from our solar O&M group – Jimmy Diaz and Jim Hanson, who work with me on some of the large scale solar systems. Tracking technology shall be installed to capture the afternoon sun, APS Peak. We get more bang for our buck with trackers. Ground treatments for weed control is recommended. We see situations where we go out on site that are maybe third party owned and there's weeds everywhere. APS provide weed control on annual basis for all APS-owned clients and substations. Inverters with modular designs will aid with O&M downtime of equipment. So if there's a component that fails, we can simply replace that module and get the system back up and running. Inverters shall represent 5 to 10 percent of plant to minimize down inverter output during maintenance. So if you've got a situation where one inverter represents 30 percent of a solar plant, that's probably not a good idea. You're taking 30 percent of a solar plant out to perform maintenance, versus 5 to 10 percent. Most plant failures occur at the switch gear level. I suggest spending a little bit more money and time in ensuring more robust switch gear is installed. Most of the failures occur there. Switches, fuse blowing, faults, grounding issues, breaking problems, etcetera.

Slide 39: So this is kind of a segue into what Dave's going to talk about, but basically just going over some challenges with smart grids, smart inverters, interconnection communication standards, ownership issues, solar forecasting and resource planning, load management under high pen scenarios, feeder reconfigurations might be needed, distribution planning for high penetration scenarios, tools and capabilities, DOE high pen study, in-house tools, feeder loading tools, training education and awareness. We need to be able to educate our personnel, the outside, our customers. Building the infrastructure to control numerous different distributed resources. Who will have control and what O&M requirements will need to be implemented? Now I'm going to turn things over to Mr. David Narang, who's going to talk about the tools and capabilities. Thank you.

[Speaker: David Narang]

Slide 40: Thank you very much, Frankie. Good morning. It's my great privilege to be here on behalf of our high pen team, and we're very grateful for the chance to share some insights from what's probably our most thoroughly documented case study. And before I get started I just want to make a point of clarification. Stuff we've talked about before – Frankie's talked about some sizing and so has Elsa and Rachel. What we have focused on, on the team that I've been working with, is really that under one megawatt distributed resource. So when you start thinking about aggregating large amounts of, say, residential or less than one megawatt commercial systems, that's been the primary focus of our work.

Slide 41: So this, as it says here, the DOE is funding this study. I just want to say that I do not represent DOE, and if there are any mistakes, they're all mine in this presentation.

Slide 42: So here's a quick look at our agenda. First we're going to cover our overall goals. Then I'm going to spend a couple minutes on background information just to give you the baseline context for our efforts. And then I'll briefly describe our project focus, our approach, and give you a quick snapshot of the most important learnings. Then we're going to talk about how those learnings have identified gaps in our knowledge and our processes. And, finally, I'll give you a glimpse of what we plant to do about it going forward.

Slide 43: So as has been mentioned by Frankie and my other colleagues earlier in the presentation, we're fortunate to be blessed with excellent sunshine and the great solar systems that come along with that. So, to review, just here's a few of the groups or functions that might be affected when we have a large amount of distributed generation on our feeder. Frankie talked about some of the operations concerns. As you know, safety and reliability of power distribution and greater operations are of primary concern. And, also, system planning as Rachel described earlier, to find out what the peak is. One of the nuances that we're finding out from our study is that in addition to looking at system peak levels, we also need to incorporate the concept of minimum daytime loads, where solar energy systems can be aggregated and are most productive. So other folks in this series of presentations have talked about that concept, and we're aware that we need to take a closer look at that.

Of course, as you increase the amount of systems, whether they're owned by APS or not on our system, economic fleet dispatch for our power marketing and trading operations becomes more and more important. But also, as Frankie was talking about, interoperability and how these plants behave, we need to ensure that as we increase the number of, say, smart grid devices that are either existing on our feeders or new ones, we need to ensure that interoperability continues as we introduce these things like dynamic smart invertors and so forth. And we can't ignore that there is a considerable amount of infrastructure that needs to go behind the scenes, like all of our communication networks, and all of the databases that are required to kind of track all of this information.

Slide 44: So you've seen kind of our want list. I'm just going to give you a quick look at where we are in terms of our baseline for answering those questions.

Slide 45: So this is simplifying it, but really what we do in terms of our internal processes for going about an answering those questions that we have really falls into kind of two major blocks. One is situational awareness. And two is the power systems studies and tools that we use to analyze some of these phenomena. So in terms of situational awareness, Rachel talked about our reliance on EMS historical data to go out and data mine for, say, feeder peak loads and so forth. We of course have additional metering from some of our other equipment, like re-closers, say, and then we have a very actually pretty good GIS tool that gives us information about the spatial location for not only specific equipment on the feeders but also we've started including where the DG is located on the system as well. So Rachel talked about some of these studies that we go through, but basically a lot of steady state modeling for power flows, and, of course, for protection coordination. Really, we don't get into dynamic modeling unless we have large power plants that are connected to the transmission system.

Slide 46: And so as we looked at kind of where we were, we realized that there were gaps in our ability to describe what I talked about – about what happens when we have a situation where we have aggregated DG that amounts to a large amount. We realized that we really didn't have a good handle on the process or the tools maybe. So to address the gaps we looked around for projects that could help us answer the question, and our team was fortunate enough to win a grant from the DOE to pursue this study.

Slide 47: So here's a quick snapshot of the project and goals for the Department of Energy high pen study. Basically we want to understand any grid integration challenges when a relatively large amount of solar generation is concentrated in a small area. By 'relatively large', I mean 15 percent of the feeder peak load, as measured at the feeder head. In our case, during low load times, this translates to over 30 percent of the feeder peak. So our project design is heavily based on three things. First, we're demonstrating a data acquisition platform that can help us see, study, and manage the deployment. We want to see what it takes to field equipment and to maintain it. And we're basically finding a bookend for how much it would take to get as much information possible from these distributed solar plants. Secondly, our project partners are developing and validating electrical models of this specific feeder under question that we want to be able to use these processes that were developed for this analysis onto some other feeders. And, finally, we're interested to see if they will exercise any grid support features of things like smart inverters or energy storage that would be complementary to high penetration solar. So, in a nutshell, we want to use this project improved tools and processes and analytics that help increase our capability in managing high pen solar deployment.

Slide 48: So here's a slide that shows our project partners in this. Our many thanks, of course, go to the US Department of Energy, which provides major funding for the study. In addition, the solar deployment for this was in Flagstaff, and was funded by APS rate-payers through the Flagstaff Community Power Project, which was approved by our corporation commission in 2009. APS is leading the study and has also provide funding for data acquisition systems. So the teams directly working on this study alongside the DOE and APS are Arizona State University, focusing on steady state-modeling and protection, GE Global Research, focusing on a smart invertor demonstration, GE Energy Consulting, focusing more dynamic modeling, and the National Renewable Energy Lab, focusing on visualizations and verification of our approach, as well as compiling our learnings into improved processes. So we're working with Dr. Jim Kale and Dr. Moraly Bagu out of the NREL lab in Colorado. And, in addition, we have Viasol Energy Solutions supporting all of the data acquisition systems.

Slide 49: So it's been good to hear other folks, as we've been sitting in on these discussions, and the learnings that we've heard about in these series of webinars – our work is pretty complementary to that in what you would expect. Keep in mind that what a lot of us kind of now take for granted was not common knowledge even a year or so ago, okay? So there's been a lot of fast moving work. There's a lot of teams now looking at these sorts of issues, and it's great to be working alongside that.

So some of the key findings, it's just one slide. There's a lot of work that goes beyond this, and I don't have time to present all of the great work that we've done, but here's just a quick snapshot. So the greatest voltage change does not coincide with the largest PV site. Now, why is that? That's because, as we all kind of now know, no two feeders are alike. The reason that a voltage change will occur due to solar power plants, for example, is heavily dependent on where it is in relation to other loads, where it is in relation to the source, and the type of feeder that it's on, the type of line that it's on for that specific line section. So we can't overlook the impact of distributed PV, especially if we try and place large amounts of PV in areas of high susceptibility. We already know a lot of folks have talked about high susceptibility is at the end of a long feeder, that's a high susceptible area.

But we've also found in our studies that variability from load fluctuations can sometimes far exceed variability from PV, and so we know how to handle load variability, and, just like that, we should be able to handle variability from PV. We've also realized that this concept of percent penetration is not the most effective metric for determining impact from PV systems. So that really means that we have to do a lot more modeling. And a lot more modeling at multiple time scales, in addition to kind of the snapshot at feeder peak and even minimum daytime load, in order to really do a good job of planning, moving forward, I think we really need to do a lot more what's called quasi-static time series.

Slide 50: So, quick jump into kind of what we plan on doing about all of this.

Slide 51: I'll just talk about the gaps that are – so this is what we showed earlier in terms of kind of our current baseline. But in red, I've colored in what we have kind of identified through our analysis and work so far what we think still needs to be done. We need to get a better handle on specifics on the PV systems, and, once again, I'm talking about this small distributed system. And so the – once you aggregate them up, they start making a difference, and we need better information about where they are, so we can do a better job of modeling them. We need to do a better job for doing some analysis on how these devices are going to be interacting with each other when we start including some of those dynamics that Frankie talked about, and a lot of talk has been going on about smart invertors. So there's a lot more work that needs to be done about how that will happen and how it will get implemented into operations, basically.

As we start kind of thinking about planning for the future, we know there's a lot more work that needs to get done in terms of solar forecasting. To get a good estimate of what DG is going to do in the future, you need that good solar forecast that you can feed into your electrical models. And one of the things that Rachel talked about is during a feeder reconfiguration. It's a pretty common occurrence in certain parts of our territory, but we need to do a better job of trying to figure out, okay, what happens when we have a situation where we are transferring to or from a feeder that has a large amount of solar on it? So that is another area where we need to kind of increase our scrutiny and our capabilities. And as we start having increased amounts of DG, I think we still have a little bit of work to do for power quality analysis, harmonics. So far, we haven't noticed any issues outright, but that's still something that we need to keep continuing to monitor.

Slide 52: So these are just some of the groups, as a company, that we're working with to develop these tools, tools that we hope will help each business unit in integrating solar into common practice as we move forward. And I don't have time to go into all of the tools that are currently under development, but I'll give you an example, for example. As I mentioned, we're working with the National Renewable Energy Lab as part of our project team. Part of our analysis required to develop very high resolution – one second information about PV generation. Usually, when we do metering, it's not that fast for smaller power plants. Our production meters on PV systems only measure at 15 minute increments. But what in conjunction with the NREL team we utilized their solar system advisor model, and developed basically a APS business process that would allow us to send information for a specific power plant and in conjunction with a weather feed basically synthesize a power production profile for that specific power plant at a very high resolution.

So this type of tool is now currently being used by our solar O&M group to validate their performance ratios for solar power plants. So I think as we move forward we're going to see a lot more partnerships, and I just wanted to thank, in closing, Courtney, again, for this chance to talk, and it gave us a chance on this side to get together and talk about this stuff. So that's the end of our talk, and thank you very much for the chance again.

[Speaker: Kristen Ardani]

Slide 53: Thank you very much, David. And, also, there are some references and sources for further information here up on this slide, if you'd like to take a look as well.

Slide 54: So now we'll go ahead and get into the questions and answers section, and we will get to as many questions as time allows, and I have noticed there have been some more detailed questions, so if your questions are not answered during this session, please feel free to reach out to us and we will connect with you offline. Okay. Let me see here. How about – Frankie, I think this might go to you. Does APS have a system for tracking the locations of all customer-sided utility – hold on – utility disconnect switches? And, if so, are they –

[Speaker: Frankie Greco]
Well...

[Speaker: Kristen Ardani]
Go ahead, and I'll finish the second part of the question.

[Speaker: Frankie Greco]
We do have everybody – we require every system, every interconnection, if you would, has to submit drawings in accordance with our requirements. We need one line three line site-plant plant location and array diagram for your basic PV, even if it's – wow, I'm getting a lot of feedback – even if it's rotating machines, we require the diagrams. Our GIS, our system, maps all the different PV systems, all the different backup systems out there, and they're all identified via that system as well. So we'll have drawings and we'll have a mapping system that'll identify the switches. As far as procedures, the operations personnel will work with, and are working with, our union folks, the union side of the business to develop standards and practices for opening and closing disconnect switches on systems that are less than 600 volts, because those are placed under our operational jurisdiction. Anything that's greater than 600 volts, we have an operating agreement. The customer will sign the operating agreement. The customer will provide the personnel and the grounds to open and ground their side of the generating facility. Hopefully that answers the question.

[Speaker: Kristen Ardani]
Okay, great. And then here's another question. What drove you to decide that generators need to be set at 98 percent of absorbing VARs? Is your character adjusting for you to provide those VARs subset the generators are not getting them for free?

Frankie Greco: No, it's definitely not the tariff, so I'll just kill that right then and there. It was based on the placing a plant on 9-8 percent power factor has the – is the less complex, less impact on the system. We'll see less variability with our transmission system at 0.98 power factor, and it's probably the most stable mode once _ _ a plant in is absorbing VARs. Especially in the middle of nowhere, where that system is back feeding the grid, raising the voltage above and beyond where we feel it's acceptable, having it absorb VARs at 0.98 keeps the voltage pretty constant, pretty steady at the

12 KV at the substation. And as I mentioned at part of my portion of the presentation, our operations engineering folks will decide and will run studies to determine if the mode that we've put the plant in is the best mode to be in. They may decide that they want to go with 0.97 power factor. They may want to provide VARs. Because we're in a low voltage part of our distribution area. We may want to go with voltage control, because we have some – the voltage is all over the place throughout the entire course of a day. Maybe we want to go with voltage control. So the operations engineering people will be the ones to make that final decision as far as where we – when I walk away from a plant and hand the keys over to our solar O&M folks, we set it at 0.98 power factor.

[Speaker: Kristen Ardani]
Okay, great.

[Speaker: Frankie Greco]
Okay, and let's see, there's another couple of questions.

[Speaker: Kristen Ardani]
Yeah.

[Speaker: Frankie Greco]
Utility.

[Speaker: Kristen Ardani]
It looks like, yeah, there's a two part question.

[Speaker: Frankie Greco]
Yeah, I see, I'm looking at it right now.

[Speaker: Kristen Ardani]
I can go ahead and ask it so that the audience can hear it. And has the utility community prioritized the use of distributed generation and support critical infrastructure during or immediately after an emergency?

[Speaker: Frankie Greco]
Okay. You know, that's something that I have not gotten involved with as far as an emergency response type situation. And the way I can address that is we try to provide just in general – and there may be some parts of our service territory that have a radial feed and it's on a weak system and we may want to come up with an alternate solution for those folks in the event that there's an outage and we may want to put a distributed resource out there to provide

a reliable service to them in the event that there's an outage. Typically may occur during the summertime, during the monsoon-type season, if you would. But for the most part we haven't entertained dispatching that type of technology right now, but more than likely we will be entertaining that going forward. And as far as who pays for what, and what type of components that's going to look like, it's really too soon to tell. We may go with battery storage. We may have some micro grid technology going forward. We're working with some partners right now about looking at a micro grid at some of our larger customers. So that might be something we look at going forward.

[Speaker: Kristen Ardani]

Okay. Great. And I encourage all of the attendees to please submit your questions. And what was the weather source used to generate the one second simulation data?

[Speaker: David Narang]

Yeah. Great question. Most of the commercial kind of weather services do not provide one second data. We developed an instrumentation package and fielded our own weather stations for this particular study, and we're using it basically to feed. So it's our own weather stations. And, since this was part of a DOE study, the kind of plans for that weather stations and the component list, parts list, all that sort of stuff, as well as probably some drawings, are part of our phase one report, and you can get to it from the third bullet here under 'additional resources'.

[Speaker: Kristen Ardani]

Great. Thank you, David. It looks like that is all that we have. There are a few questions here that have not been answered due to the fact that they're just a little bit more detailed, so we will follow up with you offline. But what's that, Frankie? Did you have –

[Speaker: Frankie Greco]

There's one question that just came in. And I'll try to hit it. Okay, so the question is, "The micro grid you mentioned – will any of them be DC-based?" Well, the source is going to be DC. The power, the solar panels. But we're going to use invertor technology. We're going to go from DC to AC. We're going to pack – we're also going to possibly look at packaging that with some battery storage. So the battery storage will be DC, but that might be out of scope. We may not have that. We may not know about _ DC _ batteries and battery storage until later. And I'll mention that briefly in a second here. We also have spinning mass, rotating machines, generation units that will be used in conjunction with the micro grid. So basically the way the micro grid works is there's an outage on the APS system, the customer wants to back up their entire load, so what they'll end up doing is separate from us, they'll back down their PV that happens during the day, they'll back off their PV, they'll go on their spinning mass, their generation units, and then they may start firing up some of their PV to sync, to have the PV sync with the generation.

They may also have battery storage to help with the interoperability, the voltage variability, if you would. But that's just very high level. If you want to check back with us in about a year or so, Kristen, and Courtney, rather, we might have some more information to share with the industry.

[Speaker: Kristen Ardani]

Okay. Thank you very much. If we don't have any more questions, I'll wait here for just a minute, see if any more questions come in.

[Speaker: Frankie Greco]

There's a couple of things that may be worth mentioning. I know we, you and I, had talked a couple weeks ago about the utility side and what we've experienced as far as growing pains as a company. We had, initially when we started, just the mass volume of work. We had three or four groups of people handling different tasks, if you would. We had Dave's team downtown handling the research projects. We had a residential renewable energy team handling the mass amounts of applications coming through the door. And you saw in our presentation that we received 9,000 last year. And that's really quite the volume of applications to come through the door. Every single one of those applications has to be reviewed by somebody. We have to review the application, the diagrams, the drawings that come in, the type of disconnect switch a customer is going to install, the location where it's going to be – we have to approve them to put them on a solar rate. We basically have been operating in a skeleton mode with the exception of the last couple years when we staffed up some of our departments to handle the volume.

I can remember back in 2009 we had six or seven people handling residential and commercial, and then we expanded above and beyond that. We then added a team of five to six folks just handle residential. We also had asked our division CPMs, project managers, if you would, to handle the inspections. Every system –

if it was a certain threshold, 12 KV, I'm sorry, 12 KW or larger, we were inspecting those systems. Anything that was less than 1 KW we didn't inspect, but we had them sign an agreement with us. So we had a couple of different avenues that we went with volume and what not. Things have seemed to stabilize at this point, but we're still expecting quite a high volume on the residential side, and quite steady commercial numbers coming in as well this year. We're living in a non-incentive world here right now at APS. There may be some federal and state incentives, but as far as APS and standards are concerned, there are none available right now. So.

[Speaker: Kristen Ardani]

Thank you very much for making those comments, Frankie. Any other closing remarks from the group?

[Speaker: David Narang]

Thanks a lot for the chance to reach out to folks. Appreciate it.

[Speaker: Kristen Ardani]

Great. Thank you. And I just wanted to thank our speakers today – Elsa Gonzales, Rachel Sall, Frankie Greco, and David Narang – for their time today. And the files will be available on the DGIC website, which is listed on the slide showing on your screen. And I will also send out an email with a link to the files to all the registrants and the attendees for today's presentation, and once the files have been posted on the site. So, with that, I'd like to thank our speakers again, and that concludes today's webinar. Thank you for attending, and goodbye.

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