FEMALE: Good morning, everyone. I'm glad everyone's here, welcome. I'm going to do a brief overview of IRRP just to sort of set the stage. We'll be digging into a lot of these issues in much more detail as we go through the day. Monica, you touched on a lot of points that I was going to make, so I'll try to add to that rather than repeat on some of the things that you said.

So, I want to start with a little context for the day, and I think through the day we'll be talking about these projects that we're doing in Tanzania and Ghana to implement IRRP. Just to give you a little context and talk about how IRRP can help these countries address some of the challenges they face.

So, Tanzania, a country of about 50 million people, electrification rate only of about 30 percent, much lower in rural areas. Load-shedding is a common, continual problem, happens quite frequently. There are significant losses on the system, both commercial losses and technical losses. T&D infrastructure is a challenge. They rely on hydropower to a large extent. The system is about, I think, 1,200 megawatts, and, as

you said, 550 of that is hydropower. But, effectively, only about a fifth of that has been available recently. And so, because of drought conditions, it is a challenge in that resource there.

They're not currently collecting enough in revenue to cover their costs. So that, clearly, is a problem that you'd want to address through a planning process. They are moving to a competitive procurement.

Ghana is similar in many ways but different in other ways. It's a smaller country; 70 percent of the people do have access to electricity, so, better situation there.

They have the same issues related to tariffs not being sufficient to support the system, same issues with losses and T&D infrastructure requirements. Also a great reliance on hydro. Their system, I think, is about 2,700 megawatts, and hydro is about 1,200 of that. And they have been challenged recently in terms of drought, you know, and not having the resources

available for the system. They do have renewables goals and a commitment to DSM.

The level of capabilities, in terms of modeling and analysis, in Ghana, I think, is further up the learning curve. And the stakeholder engagement, I think, is broader. Many of the stakeholders there have modeling capabilities and are much more engaged than I would say is the case in Tanzania.

So, how can IRRP help some of the challenges that these countries face? I think, first, it's sort of safe to say that some form of planning is always better than, sort of, one-off isolated decision-making. I think that is true across life, people would agree on that. So, to have a planning process in place, just by itself, has to help things. And I want to say that, you know, IRRP, as you, you know, start this process in these countries, it will evolve over time.

What it looks like today will be very different from what it looks like in 10 years. Because you can’t do everything at once. You need to, sort of, walk before

you can run and build upon the capabilities over time. So, today, it may look, sort of, simple and a start. Ten years from now, a very different process. And that's how it's been in the U.S. But, having that process in place, you know, if you're growing rapidly, you need to add resources. Having a system by which to find out what the lowest-cost way to do that is, is important, and IRRP can address that.

One component of IRRP that we'll talk about through the day is demand. What is your demand going to look like in 10, 20, 30 years? Having a process in place to understand that and forecast it well is very important, not only because it helps you understand how your--how rapidly your load is growing. What is underlying that growth, in terms of what the end-use options are? What are customers doing? How are they consuming energy? What's the mix of customers, commercial versus industrial?

That's important to understand because it helps you understand how your load shape is coming about. What is the pattern of load over the year and the day, because

that's--we'll talk about later--is important in figuring out how to best meet that. But also, it helps you understand how you can manage the load. It, sort of, underlies your ability to look at demand-side resources. Understanding what the nature of the load is helps you figure out how to manage it better. What mix of resources should I add? Again, making a decision, sort of, one project at a time, gets you the mix that just evolves from that--those one-off decision-makings.

But an IRRP can help you figure out what the optimal mix is, given your objectives. Again, it may not be just a least-cost objective. You may have other things you want to achieve. But, given those objectives, it can help you figure out what the right mix of resources are to address your country’s objectives.

It will help you figure out, sort of, how do I connect these isolated systems? How do I build out the distribution system? When do I bring in these systems that may have--it's almost always immediately--but when they have diesel generators out in isolated systems, how quickly do I connect those? What kind of capital

requirements am I going to have? That's important to understand, so you can line up those investments and give confidence to people who are coming in to invest in your system. And then, do I have the laws and policies and regulations that I need to have in place to support the IRRP? So, I think, you know, we'll see that there's many areas where the IRRP can help these countries face some of their challenges, and address some of their challenges.

I want to give a little, sort of, very quick overview of, kind of the history of IRRP, just to give you some context, very quickly. So, in the U.S. and pre-1970s, you know, very rapid demand growth, 3 percent a year. The biggest planning challenge was, could you get the plants in the ground quickly enough to keep up with demand. Coal plants, nuclear plants, every one you added was a little bit cheaper on a per-unit basis than the last one you added. It was a little bit bigger, and so economies of scale were at play. Really, the planning, the supply planning, and the demand planning were not, sort of, integrated functions in most utilities.

But things changed rapidly about 1970 to '80s. There were price drops, the Arab oil embargo happened, demand was not growing so rapidly. There were many, many cost overruns at these large nuclear plants, and regulators became a little concerned about continually approving these plants. And so, there was a discussion of, well, it's not so important that we just provide electricity; people want energy services. Maybe there's another way to do that, demand-side management became very important.

Many states implemented IRRP regulations, either requiring that utilities have those processes in place before they could build anything. You know, lots of rules, I think, today, probably, 30-some states have IRRP regulations in place in the U.S. So that, you know, is pretty stable period through 1990s or so.

And then, along came deregulation, where many states unbundled the vertically integrated utilities, and IRRP became somewhat less important. Demand-side management became somewhat less important, because it was less

obvious who was going to take on that task. I would say IRRP stayed in place for many states, but some states, sort of, just let it go on the back burner.

And now we're in a new period. A couple things happened in the time since 2000 and have been coming along--the issue of climate change. Now, things are different now, today, but over that long period, climate became an important issue. And so, now you had to address, well, I have had these least-cost objectives over time, and maybe some others, demand side and so forth. Now I need to address climate.

And so, having the ability to look at, sort of, the risk, not only of climate policy but climate impacts on your system. And that is the second R, how does your system respond to potential changes in a system due to climate and weather variability? That's the resilience piece. Can I have a system that allows me to adapt quickly to either sudden severe events, like flooding and so forth, and also the changes in climate variables over time?

And the second thing that's happening is a very strong focus on the distribution side of things. Energy efficiency, distributed resources, demand responses are very--technologies have evolved to the point where those are very real options now. And so, you can’t just pay attention to the supply side of the equation. You have to look at the distribution side. And the technologies and the analytics are evolving quickly, so that you have much greater visibility into what's happening on the distribution side and can incorporate that into your planning.

And so, in the U.S. states, California, New York, Hawaii, are beginning to look at how you manage that process, so that you have regulatory and legal and regulatory frameworks to address them appropriately and make sure that evolves in the best way possible. The NERC fan, that's sort of a famous graphic that just talks about, you know, things change.

In early--mid to--you know,'70s, demand growth was, you know, just get me a ruler and let me project it. It's 3 percent a year. But every year, as NERC-- is the

National Electricity Reliability Council, they put together forecasts of all the utilities. But every year, that just kept going down as people reassessed what was happening to demand. And now, I think, demand growth--I haven't looked at it lately. I think it's like 1 percent a year, is what, perhaps even lower than that in, say, in the AEO forecast, sort of, our government forecast.

So, I want to just spend a minute talking about, sort of, what is an IRRP? What are its main components? We'll go through a lot of this over the day, so you'll, you know, I'll keep this at a pretty high level, but here’s sort of the defining characteristics of IRRP. Considering all resources, as I said, historically, it was coal plants, nuclear plants. It evolved to include all resources, and now that is a pretty wide range of things that an IRRP should consider, in addition to supply-side resources.

So, demand-side resources, could be clearer energy efficiency, could be demand response. Could also be pricing mechanisms to, sort of, control when demand

occurs. Distribution side, we talked about. There are now storage options, many distribution generation on sort of the other side of the meter you need to worry about. And also looking at transmission and distribution. Maybe it makes sense to build either T or D instead of a supply option. That may be an option. And so, now you should be bringing that into the equation.

This notion of a level playing field, we'll talk about that a lot today, too. It's not appropriate to compare a peak-shaving demand-side option to a baseload combined cycle plan on the basis of levelized cost of energy. That just doesn’t make sense. And so, IRRP gives you a framework in which to appropriately compare those two things, apples to apples.

One is, you know, shaving peak where it is very expensive to supply load. One is, sort of, running constantly on an average cost basis. And so, that's what the level playing field notion is. And that generally means you need some more sophisticated planning tools and methods to look at that temporal--

get some temporal resolution to the problem. And we'll talk about that through the day as well.

Planning horizon, Monica mentioned this. Yeah, typically it's 20 years. These are long-lived assets. They have long lead times to build. And then, in the case of DSM, you need time to, sort of, move the market and have these programs.

Risk and uncertainties, and IRRP should consider those, and, you know, and utilities have considered those over a long period of time. So, you have fuel price risk, demand is uncertain, you need to consider that it may not be exactly as you forecast. That there's some range around that forecast. Technology costs and performance change over time. And then this issue of climate risk--can your system respond to changing climate conditions?

So, you know, as a planner, you might have always looked at the variability of hydropower output. There’s a normal expectation of what you'll get, and there’s a range, and you certainly should be looking at that. But what you might not have been looking at is whether

normal is changing. So, in 10 years, is what you think, you know, your output is today, is that what it's going to be in 10 years or 15 years? It could be much lower because of changes in precipitation. Competing uses may change, you know, because of climate as well.

So, that's what we--what the second R is about, just factoring that into your system. You might have flooding risk at some of your plants. Do you need to do something to harden those assets against that, or move them, or take some action to make sure that asset is available in 20 or 30 years

You may have objectives other than just least cost. Monica talked about that a little bit. This should not be a least-cost planning exercise. You have other--and they may not always be related to the power sector. As you said, it could be social goals, economic growth, diversity, national security issues. The IRRP is a framework to use to, sort of, put a cost on those things. What does it cost me to want to have a more diverse fuel mix than my least-cost plan might have indicated? What does it cost me to meet a carbon

emissions goal, either voluntarily or in response to a requirement?

Some of these goals might be represented in your IRRP as a constraint. In other words, I must do these, every plan must satisfy this, like an emissions policy, perhaps. Others might be criteria against which you measure different plans. So, I have a range of plans I'm looking at, what are the rate impacts of those plans? How do they differ, if that's a criteria. You know, it might be a metric from which you measure a plan.

Most IRRPs have a stakeholder engagement process. Monica talked about that as well. So, you know, your stakeholders may be a source of data. They may be a source of input to scenarios and strategies you want to examine. Certainly, having them engaged increases the buy-in. It doesn’t ensure it, but increases the buy-in and confidence in the results. And it may typically include regulatory bodies, consumer groups, and industry groups.

I think the Tennessee Valley Authority in the U.S. has one of the better, more exhaustive, stakeholder processes. They have, I think, probably over the course of a year, maybe a dozen workshops where they go in very great detail over what the IRRP process is, and, you know, get input to it. A really detailed set of information out there that they provide. So, that's one extreme.

The other, in Massachusetts, at least when I worked there, you would file an IRRP, the utility, the siting council would review it. There'd be a 60-day review process from the public. There'd be a hearing, and then it would be approved or disapproved or modified. But they had to have that in place before they could build anything. A different process, but the same objective.

Periodic updates are important. This is one of my favorite quotes, "All models are wrong; some models are useful." You can bet that your IRRP plan, as you project it today, probably won’t evolve that way. Things will change. Drivers change, costs change, technologies change. We talked about the uncertainties.

And you'll, no doubt, have to have a course correction. That doesn't say you don't have a short-term action plan that you should be working through. But it may, again, need some course correction over time as variables change. And so, you need to update this and evolve them, evolve the process in terms of its sophistication. You know, again, the IRRP process you have today may look and should look different than the one you have in 5 or 10 years.

I'm going to spend, not much time on this graph, because I think we come back to some of these issues. But I just--this is about what--given the elements of the IRRP, how do they change planning? So, let me just pick out a couple of these and talk about them.

So, the one I want to focus on is this least-cost, system-level modeling. So, you know, a simple planning method, as we talked about, you just look at every project on its own, give me a levelized cost of energy, let me compare them. That has a lot of problems inherent in it, (A) you don't know that those projects

have been evaluated on the same set of assumptions. And that's kind of key. You can't--you need to put them on a level playing field.

You also need to account for, as we talked about, temporal issues, like, how is your demand changing within a year, but also across time? And how are fuels, demands, and those things changing over time? So, generally, an IRRP, you need to have some level of sophistication in your modeling. And we'll talk about some of the tools, later, that are used.

And there's not just one tool. There's multiple tools, and you need to integrate them and figure out how they are going to feed each other. And, generally, that's what it is. You're, sort of, using one model to drive inputs to another model.

Resource option assessment--that's kind of the same point. You need a, sort of, a level playing field, again, to look at your resource options. What are my technologies that I can choose from in the future? And have I, sort of, lay them out and evaluate them on the

same basis, rather than picking and choosing among different assumptions. You need to, sort of, have one set of assumptions there.

So, demand forecasts, we talked about that. That is, sort of, a key driver, something that you need to evolve over time. Again, that's not something where you're going to go to the most sophisticated approach overnight. You're going to have to build your capabilities there. But it really drives, not only how much resources you have to put on the ground, but also how can you shape--can you get DSM programs to shape those resources? We'll come back to some of these across the day.

This--I just--is a graphic representation of IRRP and the components. And we'll go through these over the course of the day.

Supply-side and demand-side issues, characterizing the costs and performance of your resources, existing and new, including transmission and distribution options and DSM options.

So, that's a first step. And I characterize everything that's available to me now and that might be available to me in the future.

There is a least-cost planning model where you do look at what the least-cost option is, but you want to look at scenarios.

There are uncertainties you want to characterize, and examine those in the modeling framework.

And then you may have strategies you want to impose on the system. I want to have a certain level of renewables on my system, or I want to address carbon emissions.

And then you need to build in the resilience piece. How is climate potentially going to change over time, and how is that going to affect these components? How do I incorporate that? And then it's, sort of, an iterative process resulting in, ultimately, a master plan. We will talk about a lot of these components today.

So, I think that's my last slide. So, Bill is going to talk about the demand side in more detail, and then Maria.

MALE: So, I wanted to talk a little bit about the right-hand side of this diagram here. So, you see these supply-curve charts done a lot in our field, levelized cost of energy from various sources. But as Juanita pointed out, levelized cost is just one metric of whether a resource is appropriate in a particular context.

So, energy efficiency usually pencils out as the lowest-cost resource on a levelized-cost basis, two to four cents a kilowatt hour. That’s great. So, why doesn’t everyone just do that first, which is a legitimate question. One issue, which we'll get to later is, depending on how efficiency is procured, the first-year cost of efficiency could be up here, because program costs are recovered in a single year. Whereas you can get an independent power producer to sell you energy on a levelized-cost basis through auctions or other methods. So, those details are really important.

So, not to mention the market barriers that efficiency faces, which is why incentives in policies are needed to get markets to actually shift. So, that's just kind of an intro. This is a very tantalizing number, but to actually realize that number, there's a lot involved, and IRRP is really a key part of that.

So, here’s a little thought experiment that I did a few years back to try to explain why energy efficiency is important to clean energy development. Because a lot of folks rightly think, well, we're just going to ramp up wind. We're going to ramp up solar. We are going to ramp up hydro. We are going to ramp up every clean energy resource we can, which is represented by a yellow line, like this.

This is, sort of, a generic, aggressive development scenario for clean energy. But then, you have to look at the top line. Demand growth. So, if this is historic demand growth, what you see in these two lines are diverging. Demand is growing faster than clean energy supply. You can’t just dial up clean energy. You can’t

just order a dozen wind farms to be delivered next year. It's a struggle to get resources to market. So, it's really a battle between how fast you can develop clean energy and how fast demand is growing.

And in a lot of developing countries, we know that clean energy development is chasing rampant demand growth. And as long as those lines are diverging, your emissions are increasing, whether you're talking about criteria air pollutants, like sulfur dioxide or greenhouse gasses.

So, this is the challenge. If you can bring energy demand down, these lines begin to converge somewhere out in the future. And we often just don't see the picture as a whole that way. You have to match up clean development on the supply side with unattainable demand goal. So, just a little intro on that point.

One of the interesting aspects of the slide that Monica showed on the Northwest Power plan is that efficiency was meeting the great majority of demand growth. But it's also important to know that that was the seventh

power plan. So, they've been at it in the Pacific Northwest since the Northwest Power Act was passed in 1980. So, they've been bringing demand growth down year after year after year.

So, when demand growth is down in the 1 percent or less range, you can get energy efficiency programs to attain savings on an annual basis that are close to, or even above, 1 percent per year. If your demand growth is 10 percent per year, it's going to take you a long time to bring growth down. So, it's--that's all to say it's a long-term challenge. You have to stay in the market for a long time.

Another framing point that I think is important to make, is that energy growth and GDP growth are a religious issue in the eyes of many nonenergy experts. In Tanzania, in the course of our project, a number came across our email inboxes. The number was 1.68. 1.68 was determined, according to a study done by someone, that the ratio of electricity demand growth to GDP growth was 1.68. Which means that for every dollar, or for every percent of GDP growth, you needed 1.68

percent growth in electricity. Which meant--which means, if you want GDP to grow to 5 percent, you have to grow electricity demand at 8 percent. And that became a religious belief, which drove a lot of assumptions about, well, we need massive investment in power development.

However, the data shows, over time, that energy intensity, which is energy use per unit of GDP, actually has been declining, and not just in the OECD countries, but even more rapidly in the non-OECD world. And that is partly due to structural changes in the economy. It's partly due to energy efficiency. There have been laboratory studies of the relationship between structural changes between energy-intensive manufacturing sectors, less energy-intensive service sectors, and so on. But energy efficiency is generally found to account for the majority of that decline. So, this is really an important point, because it helps to explain the chart that Juanita showed earlier. Which is that energy, electricity demand in particular, but energy demand tends to decline over time as economies mature. And this is a fundamental point that has to be

brought home, and IRRP is one rigorous analytical way to do that.

I mean, in the U.S., in the 1950s, electricity demand growth was two to three times GDP growth. By the time many of us got in the field in '70s and '80s, it was down closer to, maybe, parity with GDP growth. Now, in the U.S. and much of the OECD, electricity demand growth is well under, you know, well under par with economic growth.

Recent years in the U.S., it's been under 50 percent of GDP growth. So, that's an important point to understand, that, really, IRRP allows you to decouple that assumption and allows you to keep from overbuilding coal plants, as happened in China. I mean, it's not that the Chinese weren’t promoting energy efficiency, because they got very aggressive during the 1990s. But there was no integrated process that connected decision-making on the demand side with decision-making on the supply side. So, people whose job it was to develop power plants just kept at it and you know, the lines did not get integrated soon enough.

I want to talk a little bit about some of the enabling regulatory issues. And I know Maria is going to get deeper into some of these issues later on, so I'm not going to spend a ton of time. But these are really important points. So, you have to fund DSM activities, just as you have to fund any resource acquisition.

So, a few options that we've seen, at least, are through a general rate case. So, maybe in a few years you go to your regulatory commission, you say, well, we want to spend X-many million dollars, or whatever the currency is, on DSM. And maybe you get approval, but maybe you don't get to recover those costs for some years down the road. That's not a great business model for a lot of for-profit utilities, or even for publicly owned utilities, because you are deferring revenue.

Many cases, you see a specific rider, a specific mechanism attached to the tariff structure so that you can recover costs in current year. So, whatever costs are approved, they just go into that rider, spread across all of the kilowatt hours, and you have your

money at the end of that year. That's much more preferable from a utility manager’s point of view.

You can also get public funding. In the U.S., we have several states, which have what we call public benefit funds, where there is a small charge, a universal charge, on all rates. But that goes into a public pool of funding, and that funding might be administered through a nonprofit, through a state agency, or through a utility. So, slightly different model there.

What I call revenue stability, sometimes called revenue decoupling, has to do with the way that costs are recovered in traditional, what we call volumetric, rate-making. So, if you have a billion dollars of costs that are approved to be recovered, and you have 10 billion kilowatt hours you're expecting to sell that year, you divide up all the costs across 10 billion kilowatt hours. And that works out great as long as you sell 10 billion kilowatt hours. If you sell fewer than 10 billion kilowatt hours, you're not recovering all of your costs. So, there is a built-in bias towards meeting or exceeding your sales goal.

And if you're in a country like Tanzania, where TANESCO is not recovering its full cost of service on every kilowatt hour, you desperately want to sell more kilowatt hours than you planned, because you actually begin to dig yourself out of a financial hole. So, this has to be dealt with.

There are mechanisms to do that. You can create another rate-rider–type mechanism, where if kilowatt hours are a little low, a little more money is collected the next year. If they're a little high, a little less money is collected the next year. So, several states in the U.S. have done that. It's a way to address that problem.

Then there's the question of, does the plan have teeth? Are the decisions that are actually made following the planning process, actually reflect the analysis and the logic in the plan? So, for example, can a power plant be approved if it's not in the plan? Or if a resource, like DSM, actually costs less in the analytics in the plan, is there anything that ensures that it gets constructed or acquired first? And does the regulatory

authority have a particular process for doing this? And the general rule is no.

There are some jurisdictions, California being one of them, where the utility commission has said no, you have to do all cost-effective, demand-side resource acquisition first. If you still need to build something or acquire some supply, it has to be renewable, and only then will you be allowed to build fossil energy. So, that's more the exception than the rule right now.

But those are really important issues, because otherwise the plan doesn’t necessarily lead to rational decisions in the field. And last slide, as we said, there is no assurance that DSM resources, or any resource, will be acquired, and so you need a rational procurement process.

Monica referred to auctions and reverse auctions, and that's something that has been done for DSM in some jurisdictions. It's still not the most common method, but there are energy service companies that will participate in those auctions if you hold them. There's

the more common method of utilities actually implementing the programs directly. They might have contractors; they might not. They might use their own staff. But the utility is really spending the money, running the programs, and recovering the costs. And we also see third parties. Several states in the U.S. actually separate the implementation of DSM from the distribution utility. So, different ways of doing it.

And, as I mentioned, there are, in a few cases, loading-order procurement policies that say you have to do these resources first, and then these, and then these. Still, the exception rather than the rule. And so, that is a very quick framing discussion for demand-side management.

As Juanita pointed out, DSM can take many forms. Energy efficiency typically has the largest total energy impacts. But a lot of utilities are very interested in peak-load management under what we'll call demand response, because capacity is really an important consideration, especially for, you know, capacity expansion. And pricing does come into this. We've done

time-of-use pricing analyses and training in Tanzania. And we're actually getting some traction now in Ghana at a time-of-use pricing scheme, because that's something you can implement quickly. And you can go after a very targeted customer class and get a lot of demand impact in the short term. So, a lot of different flavors we'll get into there. But I want to think--I think it's time to now turn the mic over to Maria, who is going to--question back here, yes?

FEMALE: Question, in the places where there are these loading-order procurement policies, has that created an incentive for funky modeling or other ways to, sort of, work around? Like, how political does that become because utilities feel locked in, or is there not data there, yet, as we look at this?

MALE: Well, I would say that depends on the transparency and the rigor that apply in that jurisdiction. So, in California, which is the most notable, the Pacific Northwest is another example, the stakeholder process is very detailed. And all of these working papers that are developed are subject to public comment and review,

and it's very difficult for anyone to get away with any unsupportable analyses.

Some would say the analytical process can achieve almost a paralytic state because there are so many people commenting. But the point there is, that there's very little chance that something will go awry because there's so many people looking over shoulders. If no other questions, I'm going to hand the mic to Maria and go to the next step.

FEMALE: I wanted to talk a little bit about the whole process, again, on who uses IRRP and why. And we've already heard, let’s see if I get this right, we've already heard a little bit about some of the IRRP processes from Juanita and Monica this morning, including the South Africa IRRP, the Tennessee Valley. South Africa being a fairly developed electric power market. TVA certainly a very highly developed power market with interactions with multiple power systems.

And a third example that we'll focus on--or that touch on--is Malawi, which is really a underdeveloped

country, similar to the work that we're doing for Tanzania and Ghana. In fact, probably a little less developed in certain aspects there.

OK, so, what I wanted to talk about was the structure that we have here in the U.S. Where IRPs really have been in place for many, many years. But they've taken multiple forms dependent on the state in which they're enacted, or the body which is performing them. First, regulated utilities.

This is the traditional audience for IRPs. They have an obligation to minimize ratepayer cost. The IRP is a mechanism by which they can show, as Bill mentioned, analysis is important, credibility of analysis is important. Through the IRP, they can show that they are making prudent decisions, that they are not impacting their ratepayer with too much risk in any individual area.

The regulator that approves the utilities plan also has that information. All the stakeholders and parties are able to make comment on that information. But the key

goal there is, they do have this obligation. So, we're looking at scenarios. We're looking at risk management.

Unregulated utilities have a similar obligation. They also have an obligation to stakeholders, to investors. Many of what we call unregulated utilities that don't own power plants, but they still have the obligation for retail load, they're load-serving entities. They're subject to regulation by commissions, and they do have to ensure that they're making prudent procurement decisions in this place versus build decisions only.

Regulators--in certain cases they require the IRP to be filed. But in certain cases, regulators are actually a party to the IRP. Regulators, or state agencies of some sort, are a party to developing the IRP. We see this much more often now than we have in the past.

Where we have a number of states that did deregulate, their utilities were no longer required to file IRPs. But the state realized, we're lacking a mechanism to actually ensure that we're considering all of the vast resources, the developing technology. So, those

agencies have developed programs in which the utilities, too, do participate, but they're stakeholder-run programs led by a government agency, and guiding those procurement and certification processes.

ISO--so, this is independent system operators. You know, typically, they're not doing an IRP analysis. They're ensuring that you have reliability on your transmission system to serve growth needs going forward. In certain cases, they don't have detailed information about what's going to happen in 10, 15 years when they're still looking for transmission development. So, they'll run these studies that are very similar to IRPs, themselves.

New York ISO runs what they call the CARIS analysis. And the actual acronym escapes me right now, but it's effectively a long-term planning analysis looking at alternate resource integration to the system under multiple scenarios. And they use that CARIS analysis as an economic analysis of the forward-power markets. They use it in their transmission planning stages. So,

there's value, even to people who are not building or procuring power plants.

Market participants--so, there are multiple different types of participants, typically not conducting their own IRPs. I can give you a few examples when market participants have conducted an IRP. But they often utilize IRPs to help identify opportunities. So, if TVA were to come out and say, we have a need for renewables, our load shape is looking like this, and we need to fill this gap, those participants, developers, IPPs actually can use those IRPs to gain insightful information.

And not only are they gaining the information, but they're using it to rank priority markets. So, if they know that there's a well-structured utility, who can provide them reasonable revenue return, which is part of an IRP process, to identify the revenue requirements, and that the regulator is approving of that process, it bodes well for development.

And stakeholders--we talked a lot about stakeholder input to the IRP, but many stakeholders also participate at the tail end. Where the IRP has been presented, they want to get information about what the rate impact to them might be, for example, commercial entities, DSM, energy service providers. The manner in which the IRP will be used and how it will affect rates definitely drives the participation and interest of stakeholders.

So, we've talked a lot about the benefits, and I know we are a little short on time, so I am going to skip this slide. But focusing on--a little bit on the R--knowing a lot of people are still wondering, well, what is that R? We chatted a little bit about what it meant. But, specifically, in the areas that we're looking at today, actively, frequent drought has been an issue with power development.

One of the aspects of IRRP planning is to include not only a potential drought scenario--right, so it could be high hydro, it could be low hydro--but also to look at what the implications of climate change are to water

availability going forward. In all sectors, not just to the power sector, but, we have to look at agricultural needs. We have to look more broadly than just at electric needs to understand what the implication to the power sector will be. It also will affect siting, it will affect output in a normal condition, not just a drought condition. So, these are important factors to consider.

Clearly, the demand side, there’s a number of benefits from demand-side resources that can help with the resiliency aspects of the grid. And giving credit for those is not often something we've seen in IRP analysis. So, making sure we account for that, as well, is an important factor here.

And, how can it lead to better outcomes? Well, resiliency--we've talked about the flood, but--or we've talked about hydro conditions--but factoring flood plains. These are very long-lived assets.

In most cases, the transmission needs to be developed. If we can look now, today, at transmission lines that

are going to be in place 40 years from now and are the foundational elements of the grid, to ensure that we are factoring in either the ability to enhance them, structurally, going forward, or to locate them appropriately, from flood plain perspective, then we're adding value over the long term to the electric consumers.

And I wanted to talk--we have talked about how it benefits--but, what happens when you don't do IRP planning? And there are a number of examples here in the U.S. of the stoppage of IRP, traditional IRP, largely related to deregulation. The first is California. The California energy crisis--part of the--if you go back and look at, you know, what happened in California--part of the story there is, that the utilities deregulated, the government said, okay, private market, come in. We'll develop, we want to see that happen. But not as many developers came as quickly as was needed, given the potential situation with both hydro--limited hydro--and growing load.

So, the regulators--the government effectively felt blindsided. We didn’t know that these developers weren’t going to be there. We didn’t know that we should have put money into DSM programs. We didn’t know that we needed alternate resources. And reinitiated, not traditional IRP, but reinitiated procurement planning in California, which is effectively the same strategic planning effort required for IRP. And they've gone multisteps now, further, looking at distributed resources, as well. So, California is one of the first states where we're really seeing a forward momentum to include distributed assets in their integrated resource planning.

Similarly, Delaware, legislation was actually introduced in Delaware when a rate freeze came off after deregulation, and rates just skyrocketed. It was a high–gas-price period, was not foreseen. All power purchases were very high, and the utilities didn’t have, fundamentally, any control over the market or awareness of what their next resource purchase price would be.

So, Delaware reinstated IRP planning. In that case, they also allowed the utility to consider self-builds. But, largely, they were looking for long-term commitments, PPAs, through the development of an IRP process

Mexico, New Mexico, excuse me, and Montana, similar to Delaware, reintroduced IRP requirements.

Connecticut actually legislated the IRP requirements. Connecticut does a joint IRP planning. This is one where all of the utilities participate, but it's also run by the Connecticut Ministry of--Department of Energy, rather than Ministry--the Connecticut Department of Energy. And we've seen states that really didn’t have actionable, enforceable, strategic planning requirements in place, also, recently, begin to include these plans, such as Louisiana, as recently as 2012.

So, what's happened in the developing countries? We've seen what's happened in the U.S. What's happened in the rest of the world? There are a couple of examples here,

and they cross between strategic planning and power procurement.

One example that I like a lot is Brazil, and this is going back to the late 1990s, the early 2000s. A similar environment of deregulation where that strategic planning was no longer utilized. And, in fact, it wasn’t really what I would call strategic planning prior to deregulation. It was a government-controlled utility, and they did do long-term asset views, but not necessarily risk-based views.

So, we had a very dominant hydro system, no thermal power plants. The goal was to attract thermal facilities to the marketplace. There was no studies done to say how much will this cost? How much do we need to pay developers to come into the market? And, further--so, that would be the strategic study--we need to know what the cost structure looks like for developers. But further, there was no coordination with the structural aspects needed to supply gas or fossil fuels to these developers.

So, what we saw was the market actually went into crisis. There was rationing, water rationing, in place before there were mandatory governmental reforms that allowed private developers to contract for gas more readily. And, actually, the other aspect was, who gets the risk? Those IPPs, those independent power producers, had all of the risk initially placed on them, which no developer is going to take. You know, you have to design your market. You want to attract external parties to actually be a little bit of a give and take relationship. So, we saw those reforms, and we've seen a lot of development happen.

Indiana--not Indiana, excuse me--India and Indonesia also had issues, more so with their procurement and the visibility, the transparency, of those procurement processes. But, one thing that we've seen repeatedly help in procurement is having the stage development, the transparency of an IRP, to identify the processes in place, as well as the costs and the expectation that the developer will be able to get paid. There's a reasonable revenue requirement expectation in place.

So, there was a question earlier related to the DSM about, you know, in these markets, what happens? Can you, sort of, gain the markets? Can you ensure procurement opportunities? Regulatory approval in most IRPs, not all, but in most, is simply a acknowledgment that the utility is making decisions that are in line with the objectives of the regulator, with the objectives of least-cost rates, with the objectives of reducing risks to customers. It's not a doctrine; it's a guide. This is why we repeat the IRP every few years.

In most cases, you don't see exactly the plan in an IRP development unless it is a one- or two-year-out plan, where it's already in process. A five-year plan is going to change. We should expect it to change, because every time we do an IRP analysis, we want to use the best information available at that time.

The few cases here in the U.S. where they are actionable--the state of Georgia is an example. Whatever they file in their IRP is actually an approval to move forward with those IRP plans. The latest Georgia power plan had multiple approvals, actionable

elements, of their IRP, including building new resources, piloting a solar program, closing existing power plants. They had approvals of doing additional studies, which would feed later IRPs and feed procurement analyses. And this is not the norm. The norm is, do the IRP and move on to additional review.

The IRP typically doesn’t have as much detail in it as Georgia requires. This is a matter of scoping. In one example, how does the regulator want to approve projects? Does it want to have one proceeding where all of these things are considered at once? Or would it prefer to look at, you know, the pilot program in an individual proceeding--the retirement decisions in an individual proceeding.

In most cases, we see an informative IRP rather than an actionable IRP. And that gives a little bit more flexibility on individual projects, although you could approve line by line. It does give more flexibility to come back and allow the development process to move forward.

The example of Virginia, they are required to file an IRP every two years. That changed recently because of the uncertainty about the Clean Power Plan. Legislature was introduced a few years back to require them to file every year. And now, if anyone lives in Fairfax city, they've probably seen more recent activity in the legislature to make that filing go back to every two years, because now CPP seems less certain than ever.

But within Virginia, what we saw in a recent IRP, and I won’t go through these bullets in any detail, what we saw in a recent IRP was solar was identified as a resource that had value in Virginia. The Virginia IRP, the Virginia Power IRP, had probably about 100 megawatts of solar included in it, generic solar additions.

In 2015, they went for a CPCN, a Certificate of Public Need and Convenience, for a 20-megawatt power plant, solar power plant, at an existing site. And the regulator, although they approved the IRP, they did not approve this facility, for several reasons. They thought that the rain impact was too high to justify

it. They thought that it hadn’t been bid in a competitive processes.

Virginia considered only a self-build option, Virginia Power, excuse me. They did not consider other development options. And they thought the retail rate impact would be too high. It was really not a lot of certainty on solar costs. So, they denied that 20-megawatt power plant development. About a month ago, that same power plant was approved as a public/private partnership.

So, the same power plant, after two proceedings through the Virginia SEC, actually became a viable option because the means of developing that interesting--or that technology that the SEC had already identified as an interesting one for them to consider going forward--was not going to affect ratepayers in any way. It was a long-term contract with Virginia government agencies who would be taking the off-take from that power.

So, retail ratepayers would not be impacted. It was effectively designed as an incentive program that would

allow solar to be developed in Virginia. So, it takes many forms. I mean, the real point there is, it just takes--allows people to consider many different alternatives in the development aspect.

It may take time, but the more information that can be provided, the better off we end up being in developing assets that, you know, meet our objectives, which might be low power cost, but also meet our longer-term objectives to incentivize renewable development, in this case. I think we have one more slide here.

The South Africa IRP process, I think, you know, many people in the room probably know more about this than I do. It is, you know, certainly, a plan that has had a lot of development and thought put into how it would work. Right, so, number of scenarios were created. It was recognized that climate change, carbon, was not necessarily included. So, the scope was extended to a longer planning horizon to allow someone to look at that more closely.

It is a process that is repeated. It does involve stakeholders. Have we seen any actions come from it at this point? You know, that will be something that we'll have to judge as we go forward. But it has all of those basic elements that allow Georgia and Virginia to move forward with different decision aspects that they are now comfortable with. That ratepayers, that developers, that IPPs, all found attractive and can move forward in those two states. We see the same thing happening in South Africa now.

END OF FILE