PLACE: Dobbs Building, Raleigh, North Carolina
DATE: Monday, February 24, 2020
TIME: 1:00 p.m. - 2:36 p.m.
DOCKET NO.: E-100, Sub 164
BEFORE: Chair Charlotte A. Mitchell
Commissioner ToNola D. Brown-Bland
Commissioner Lyons Gray
Commissioner Daniel G. Clodfelter
Commissioner Kimberly W. Duffley
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

Storage as a Transmission Asset, Codes and Standards

Presentation by:

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and

Matthew Paiss, Technical Advisor,
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VOLUME: 6

P R O C E E D I N G S

CHAIR MITCHELL: Good afternoon and welcome. I'm Charlotte Mitchell, Chair of the North Carolina Utilities Commission, and with me this afternoon are Commissioners ToNola D. Brown-Bland, Lyons Gray, Daniel Clodfelter, Kimberly Duffley, Jeff Hughes, and Floyd McKissick, Jr.

This is the sixth in a series of presentations pursuant to the Commission's September 4th, 2019 Order Initiating Investigation in Docket Number E-100, Sub 164 in which the Commission has initiated a series of educational presentations by experts on energy storage related topics.

We're happy to have with us today Jeremy Twitchell and Matt Paiss. Jeremy is with us again, actually. Jeremy is an Energy Research Analyst at the Pacific Northwest National Lab and Matt is a Technical Advisor in the Battery Materials & Systems Group also at PNNL.

Our speakers will be working from slide decks that will be displayed on the monitors here in the hearing room. The slides have been posted on the Commission's website in this docket for your review. Our court reporter is creating a transcript that will also be filed in the docket and available on the Commission's website.

These sessions are structured for the benefit of the Commission's learning and understanding of the topics presented and the speakers will be asked to share their expertise and answer the Commissioners' questions as they have them. People in the audience won't have an opportunity to ask questions; however, if you'd like to file information in this docket in response to what you hear today or if you'd like to suggest other expert speakers or present -- or topics on which the Commission could hear presentations, please do so by filing those comments or suggestions in this docket for our future planning.

All right. Gentlemen, if it's okay with you, we'd like to ask you questions as you go through your presentations. Okay. And with that we will move forward. I think Mr. Twitchell, you are up first --

MR. TWITCHELL: Okay.

CHAIR MITCHELL: -- is that correct? Okay. Please proceed.

MR. TWITCHELL: All right. Well, thank you. It's a pleasure to be here again. Thanks for having us back. I'll take it that the first presentation was okay since you had me back.

So where is the -- the first presentation that we gave was kind of more general in nature. You know, it was kind of the basics of energy storage, different types of technology. Today I'll be diving into one topic in particular, energy storage and transmission applications using storage as a transmission asset.

So just first, again, the -- our presence here -- yes, sir.

COMMISSIONER GRAY: If you'll pull it towards you.

MR. TWITCHELL: Oh, okay. Is that better?

COMMISSIONER GRAY: Thank you.

MR. TWITCHELL: Okay. Lean in. So our presence here today, most of this work that I'm presenting was funded -- well, all of this work was funded by the Department of Energy through a couple of different avenues. We get funding through the Office of Electricity under the leadership of Dr. Imre Gyuk to do a lot of this work. The Storage as a Transmission Asset project that I'll be presenting is actually funded through the Water Power Technologies Office at DOE.

So agenda for today, I'll talk a little bit about, first, I was informed by staff that there was a request to talk about backfeeding issues on the distribution grid. The caveat here is that I am not a distribution engineer. I did talk to a very smart distribution engineer to answer some of those foundational questions that were posed and I will do my best. And if there are still questions, I can connect you with people who are much smarter in that area than I am.

Then we'll get into storage as a transmission asset, a little bit of the historical background for how we got to this point, you know, why we're having this conversation. A little bit about the technological capabilities of storage in that space.

Then we'll talk about FERC's policy statement on storage as a dual-use asset where it's doing transmission services as well as market services, grid services.

And then I'll talk a little bit about the project that we're doing to identify and hopefully reduce some of those barriers.

So backfeeding. The basic principle here is that the distribution systems that we have, the distribution lines that we have were designed for one-way flows. And I'm a big fan of clip art as you'll see in this deck. I made fun of myself a lot last time I gave a presentation like this, but I'm told that it works, so hopefully it will work here as well.

So because our distribution system is designed for one-way flows, there's a few key points. As we move away from the energization source through the substation, voltage decreases. Think of it like a water pipeline and as -- and voltage is like the pressure and the longer we go and the more withdrawals we have, the lower the pressure we have, the lower the voltage we have.

So what we do, and those are the engineering symbols for voltage regulators and switch capacitors, we just -- we have things along the line to kind of act almost like a dam to capture that voltage, step it up, and then, you know, keep it high as we move down the line.

Another implication is that if we have a fault at any point on the circuit, it can disrupt the entire circuit. And so we add automatic circuit reclosers along the way. We add things that can basically sectionalize parts of the distribution grid if there is a fault and minimize the impact to broader customers.

And then as we move away from the substation, wire diameters tend to decrease. You know, right by the substation we have to have large wires to carry all the energy that's leaving the substation, but as we move down the line and we're serving fewer and fewer customers, to save costs those -- the wires tend to get smaller and smaller and smaller. The implication there is that those smaller wires near the end of the feeder have much lower thermal ratings, which means they can carry much less electricity on them as well. So the key overarching point here is that traditional grid architecture and protection schemes are based on one-way flows.

So a few points to remember here is since this is all based on a one-way power flow, injecting power at multiple points can interfere with those schemes. So, for example, if we have voltage regulators along the way and we have too much distributed energy on the distribution line and we're having backflow, what that does to the voltage regulator is it misinterprets the flow, and so it essentially switches to the wrong end of its range and basically effectively shuts down.

Automatic circuit reclosers, their job is to isolate a section of the line, but if a DER is still energizing that line, that may create safety risks for utility personnel as they're trying to fix the fault.

The point at which backfeeding becomes a problem is highly situational and it depends on a whole lot of factors. Again, the wire diameter, thermal rating. The closer you are to the substation the more flows you can accommodate. The farther away, the fewer flows you can accommodate. So adding a DER -- excuse me -- a DER to the same feeder can have different impacts whether you're connecting close to the substation or far away from the substation.

You have to take into account the protection schemes. How has the utility planned to manage this distribution feeder? What are the -- where are the reclosers? How do they control those reclosers? You know, what do they plan to do in the case of a fault? How quickly do they work through that?

And then the type of the interconnection. So, you know, these Legacy interconnections, things that were connected more than a few years ago, we had different standards back then. These devices weren't allowed to regulate voltage. They weren't allowed to stay connected to the grid in the case of a fault. And so when you're looking at the impact of adding another DER, you have to look at what are the impacts of the DERs we already have. Are the DERs that are connected to the -- to this distribution feeder capable of providing voltage support, capable of riding through an outage? Or do we have those Legacy DERs that are just going to shut down any time there's a problem? And as we've seen in Hawaii and other states that had a whole lot of Legacy interconnections like that, that creates a whole different set of problems, because then when you get a minor interruption on the system and you lose all those devices, those Legacy devices that automatically disconnect, then the problem starts to snowball. So again, just the impact of adding the next DER is largely informed by the types of interconnections you already have on the line.

So the takeaway here is this is why we do interconnection studies. You know, no two feeders are the same. Even on the same feeder no two projects are the same. The impact of the next DER is going to be shaped by all these factors. How has the utility designed the feeder? What kinds of resources are already there?

So it's hard to say, you know, just kind of draw a line in the sand and say this is the point where DERs are going to cause problems, going to create backfeeding on a distribution line. A general rule of thumb at which it becomes a good idea to really look into this issue and really dive into it in the interconnection study is that about 15 percent of feeder capacity is where you could potentially start to see some problems. But again, that number may be higher or lower depending on the specific feeder in question.

Oh, yeah. So that's all I had for backfeeding. I don't know if that -- I hope that I've answered the type of questions that the staff and the Commission had, but if there are any others, I'd be happy to do my best.

Okay. All right. Let's move on to transmission. So the key principle when we're talking about energy storage in a transmission setting is to remember that on the transmission system even a line that is fully subscribed, has all its capacity, has been purchased, there is still going to be several hours every day where some of that capacity, maybe even large portions of that capacity are not being used.

So the transmission system is like any other part of the grid. We design it for our peak need, but we're only at the peak need for a few hours of the year, and so all those other hours of the year, all those other hours of the day there's unused capacity.

So, for example, WECC does this study every year where they look at not the subscription, not the ownership rights on the transmission system, but the actual utilization. How are these lines being used? And what they have found is that, you know, region wide for almost 94 percent of the time in 2018, their transmission lines were being used at less than 75 percent of their rated capacity. You know, if you flip that the other way, they exceeded 90 percent of their rated capacity just 1.3 hours of the year. So -- excuse me -- 1.3 percent. Thank you. 1.3 percent of the hours of the year. So even though all those rights are fully owned, they are not being used most of the time.

So just as an example of where storage comes in, so we have a city being served by a transmission line. As the city grows, that transmission line is no longer big enough to meet peak needs in the city. So we have a couple of options. We can add more transmission to serve our growing needs or we can add storage behind the constraint, and then what that allows us to do is use that first transmission line during all those hours with unused capacity to essentially fill the storage. And then at peak when that transmission line is being fully utilized, we can use that storage behind the constraints to meet local needs.

So --

CHAIR MITCHELL: Jeremy, I'm going to -- can I ask you --

MR. TWITCHELL: Of course.

CHAIR MITCHELL: -- sort of just a series of questions, probably pretty basic questions on this transmission capacity point you made --

MR. TWITCHELL: Okay.

CHAIR MITCHELL: -- previously.

MR. TWITCHELL: Uh-huh (yes).

CHAIR MITCHELL: So is it safe for a

transmission line to be -- for a hundred percent of a transmission line's capacity to be utilized? I mean, do we want to get to that point?

MR. TWITCHELL: Yeah, and we will. We likely will during certain points of the year. You know, at the peak, those few peak hours of the year we're probably there. One of the things to keep in mind is that when we're talking about what a transmission line -- transmission line's rating is it's about the thermal load. So as electricity moves through it, it heats up. And so what we're really -- when we talk about this capacity, we're really talking about what's its maximum temperature before it starts -- you know, as they heat up the lines soften and they start to sag --

CHAIR MITCHELL: Okay.

MR. TWITCHELL: -- and if they sag too much they can hit other things and cause flashover, cause fires, cause other problems. So there's actually a lot of work taking place right now. Usually when we talk about these thermal ratings, we just use one static rating and say here's how much capacity it can hold at any time. There's work being done right now to do more of a dynamic rating to say that well, you know, if the ambient temperature is colder, then the line can get hotter before we have a problem. There's a whole lot of work that would go into that type of thing, but --

So these ratings are generally fairly conservative, so yes, it is safe for them to be at a hundred percent if you're at -- if you have a very hot day, you know, unseasonably hot, you know, like a one-in-a-hundred-year-type heatwave, you may not be able to quite go to a hundred percent, but there are -- there are processes in place to create some safety when we're in those situations.

CHAIR MITCHELL: Okay. So I notice that you use 90 percent of rated capacity.

MR. TWITCHELL: Uh-huh (yes).

CHAIR MITCHELL: Is that sort of -- is that just a number that you utilized or is that some industry or accepted standard of safety or where, you know --

MR. TWITCHELL: So that's just -- that's just actual utilization.

CHAIR MITCHELL: So that's just real -- that's from real data?

MR. TWITCHELL: Yeah, that's from real data.

CHAIR MITCHELL: Okay. Got it.

MR. TWITCHELL: Yeah. And again, it's that same principle. You know, we -- because we have to build the grid to meet peak needs plus reserves, we effectively end up with an oversized grid and we're very rarely if ever actually using a hundred percent of the generation we have or the transmission capacity we have. Under normal operating conditions there's excess.

CHAIR MITCHELL: Okay. Got it. Thank you.

MR. TWITCHELL: So this case where we're using energy storage to defer or displace additional transmission infrastructure, this is the high value use case for storage in a transmission setting. There are other things it can do. Things like providing voltage support, relieving those thermal constraints and allowing -- do get more use out of a line. But when you're talking about where the money is, it's in this case where it's deferring additional infrastructure.

So why are we having this conversation? So way back in 2005, Congress in the Energy Policy Act of 2005 said, you know, there's this suite of technologies that while they're not traditional transmission infrastructure they can be used in a way that will increase the reliability and the functionality of the transmission system, and they listed energy storage among those. And there were other ones like demand response, energy efficiency, changing the way we dispatch, things like that.

FERC in Order 890 back in 2007, this is where FERC said okay, so all these utilities that own transmission lines, interstate transmission lines, when you're planning for your future needs, you need to have a transparent process. You need to allow your stakeholders, allow developers to be at the table and understand how you're planning the system and where they can potentially fit in.

Another thing FERC did in Order 890 was say that demand response is a viable alternative to additional transmission infrastructure.

FERC came back in 2011 with Order 1000 and this is where they said okay, these transparent planning processes for transmission, these are great, but they need to be bigger than just the single utility. We need to coordinate these on a regional basis. You need to talk to your neighbors, coordinate and collaborate with your neighbors. And they also adopted that energy policy language of 2005 where they identified this whole suite of technologies that can be alternatives to transmission including energy storage.

And you can see there on the map how these regional transmission planning authorities have been set up. Where there is an ISO or an RTO, the ISO generally performs that transmission planning function in vertically integrated states like here in the Southeast and in the Northwest. They're basically just loose collaborations of utility groups that get together and do this function.

So in 2008 and 2010, FERC got two filings from companies that wanted to build pumped hydro facilities -- pumped hydro storage facilities in the California market to serve as transmission assets. And to the first one FERC said no and to the second one FERC said yes. And as you can see here in the slide, there was a whole lot of nuance into those two filings. The one that FERC rejected, the developer said well, we're just going to turn this asset over to CAISO. CAISO can bid it into the market at zero dollars, and then use it however they want.

The second developer said -- basically said we will just -- we will operate it as a transmission asset under CAISO direction and we won't ever bid it into the market. And so FERC, they saw a lot of nuance here why they approved one and said no to the other. But it became clear over the years as these cases were cited by others and the developers were appealing things that that nuance had generally been lost.

So in 2017, FERC came out with this policy statement to clarify, look, storage can be a dual-use asset. It can provide transmission services and it can provide, you know, market services, grid services, but it has to be subject to these principles. You know, it can't have double recovery of cost. You have to minimize adverse impacts on markets. And the grid operators' independence must not be compromised.

So this a nonbuying policy statement, so it doesn't require anybody to do anything. But CAISO and MISO have both had proceedings to try and figure this out. And we've learned a lot from those.

So CAISO's key principles in their proceeding was they say all right, for storage to be a dual-use asset to provide these two functions it has to be selected through the transmission planning process and then it can't be allowed to potentially provide market services, but it can't come in through the market door and then provide transmission services.

Whether it can provide market services will be a case-by-case basis. If we selected it through the transmission planning process to meet some unpredictable reliability need like an N-1 scenario where something on the grid goes down and the storage is the backup to that, then it can participate in the market, because we just don't know when we'll need it for transmission. Short of that, it would just be a case-by-case determination about when and how it can provide those functions.

So the rest of that gets into some specific market areas that I think aren't necessarily as relevant here in a vertically integrated territory, but the one point that I want to make -- actually we'll just jump ahead, respectful of everyone's time.

So when we're analyzing energy storage, you know, our economics team has analyzed a lot of different projects and where there has been an opportunity to defer or displace a transmission line, that is a huge value. There is a lot of opportunity there.

And so what you're seeing here is an analysis that our team did of a project in Massachusetts on Nantucket Island. They were -- they have two undersea cables and they were nearing capacity on those and were weighing the possibility of needing a third undersea cable to meet the island's needs. They asked our team to identify and analyze some alternatives for them, and so what they found was that by putting an energy storage device and a small generator on there is a -- I believe it was a 5 MW diesel generator, they could defer that third line and resolve a lot of reliability issues on the Island.

So what you see there on the benefit side is that big huge chunk on top, that's the benefits of deferring that transmission cable, not needing to do that transmission cable right away. But then you can see all of these other grid benefits that have been incorporated as well.

Now, this has been a huge issue in the organized markets, because in the organized markets we have this -- we have separated functions where the market entity is doing one function and the transmission entity is doing another function and those don't coordinate very well, and we'll talk more about that in a minute. In a vertically integrated territory where the utility is performing all of those functions, this is less of a barrier. You know, the same utility that would be using the device for a transmission application is also the same utility that would be using it for grid services, so it becomes less of a barrier, but we still have this valuation challenge.

The way we do transmission planning, we don't traditionally look at those grid benefits. We don't traditionally analyze what are those grid benefits that we can provide. And so what we end up with is this chasm. So this transmission process, it's tightly regulated. If I'm a utility who owns transmission, my transmission is regulated by FERC. FERC is telling me how much I can make off that transmission. I'm being compensated based on cost of service, and all of that planning is done through some kind of centralized regional planning process.

On the generation side, there's a bit more competition whether in a deregulated market or a vertically integrated market, you know, through the procurement process, through PURPA, there's some degree of competition on the generation side.

But we have this regulatory chasm, because -- so taking that example from the previous slide, if we're bifurcating those benefits, if we're cutting out the transmission benefits and only looking at those benefits through the transmission lens, and then we're only looking at the generation benefits through, you know, an IRP or similar process, we're only looking at part of the benefits in either case. And that really is the fundamental challenge with energy storage from the beginning is how do you account for these benefits that aren't captured in our traditional models.

When I was here the first time, I talked about from the IRP lens about how we don't look at things like ancillary services, like flexibility, and as we better understand those and incorporate those into the model, we become more capable of identifying cost-effective products.

Well, here we have a similar problem where we have these benefits that our traditional models aren't capturing. When we're looking on the transmission side, we're not looking at those generation benefits. When we're looking on the generation side, we're not looking at those transmission benefits.

So the project we have with the Water Power Office right now is we're trying to create a bridge for that process. We're trying to understand how can we create this -- a participation model for dual-use storage where it's providing transmission and it's providing grid services. How can we generate models that are capable of considering all those benefits? Because again, as FERC has indicated and as the CAISO process said these resources have to come in through the transmission planning process. And if the transmission planning process is only looking at those transmission benefits, it's much less likely to identify cost-effective opportunities for energy storage even if those benefits may be there.

COMMISSIONER DUFFLEY: Excuse me.

MR. TWITCHELL: Yeah.

COMMISSIONER DUFFLEY: If we could go back --

MR. TWITCHELL: Yeah.

COMMISSIONER DUFFLEY: -- two slides. So I just wanted you to talk a little bit more about, you have a bullet point here, transmission deferral is a potentially high-value application for energy storage --

MR. TWITCHELL: Uh-huh (yes).

COMMISSIONER DUFFLEY: -- and you mentioned the, I guess, on the left-hand side are you saying that the deferral of transmission is that light blue, Carolina blue bar?

MR. TWITCHELL: Yeah.

COMMISSIONER DUFFLEY: Is transmission deferral always high-value potential?

MR. TWITCHELL: It is, because transmission infrastructure is incredibly expensive. It's very capital intensive. So to build a transmission line, to build a transmission project, it requires a lot of upfront dollars, it requires, you know, complicated permitting processes. So, you know, there are capital costs, there are legal costs, there are delays and a whole lot of costs, so anytime that you can defer that, push out even just a few years, then it's just essentially a time value of money thing. Where I have instead of spending this, you know, $10 million upfront, now I have this $10 million in my pocket and I can earn on it for the next, you know, five or seven years or however long I deferred it. And so that's what this analysis did.

I think they deferred the line for I believe seven years, and so that benefit is just the time value of money benefit of deferring that capital investment out for seven years.

COMMISSIONER DUFFLEY: Thank you.

MR. TWITCHELL: Yeah.

MS. JONES: But just to clarify on Commissioner Duffley's question, there are some transmission projects that can't be avoided with storage.

MR. TWITCHELL: Absolutely.

MS. JONES: Okay.

MR. TWITCHELL: Absolutely.

MS. JONES: Like if you need it for an N-1 contingency, there's sometimes when you just can't.

MR. TWITCHELL: Well, it would depend on what the specific contingency is.

MS. JONES: Thank you.

MR. TWITCHELL: Yeah. Yeah. But that is absolutely true.

And so, you know, one key point here is this happened in ISO New England, but because of ISO New England's rules for transmission cost allocation, this was a low voltage project that was designed to serve a single utility's customers and in those cases ISO New England says, all right utility, you're responsible for that. So in this case National Grid was able to defer that and capture all those benefits, and that's the advantage of being, you know, the vertically integrated utility has is if it defers that transmission benefit, it immediately captures all those benefits. It's not dependent on some kind of market mechanism or some kind of regional cost allocation.

Well, let me back up. It's less likely to be dependent on some kind of regional cost allocation process to capture those benefits.

But -- yeah. I'll just stop there, less likely.

So what our project is doing, it's a joint project between us and Argon National Laboratory and what we're trying to do essentially is figure out what are these barriers. From a transmission planning and operation's perspective, what are the barriers that prevent us from capturing the full benefits of energy storage, from capturing the market barriers or -- excuse me -- these market benefits, these grid benefits that it can provide, and incorporating that into the process? How can we recognize and account for those benefits in the transmission planning process?

So year one what we're doing is trying to identify what are those barriers and come up with a model for dual-use storage. You know, what kind of contracts would have to be in place? What kinds of processes would have to be in place? Dispatch rules, things like that.

And then Argon at the same time in year one is developing a capacity equivalence model that says okay, so if I have, you know, one, you know, kilovolt of transmission, how many megawatts of storage would be functional or the functional equivalent to that based on my use case.

And then year two we'll do a full techno-economic analysis to say okay, once we figured out how to put this all in place, how to have a model that accounts for these benefits, what are those benefits? What does that model look like that considers the full range of benefits of energy storage from that transmission planning process?

So my final slide here is just a call for input on a couple of fronts. So first in this HydroWIRES project, this storage and transmission asset project we're looking for people who have been active in this space who have an interest in this space and using storage as a transmission asset to help us understand, you know, specific barriers in, you know, one region of the country or another region of the country, one market structure or another.

Also, I wanted to just do a plug for the Energy Storage Grand Challenge that the Department of Energy just announced last month. If you haven't heard of this, there's a link to it. But the idea here is that for years now the Department of Energy has been funding a whole lot of work in the storage space but through a lot of different programs and a lot of different projects. You've heard from some of those different programs and projects in this docket.

And so what DOE is trying to do here is, you know, let's coordinate a little bit better, let's get everyone in the same room, let's give everyone, you know, some common objectives, some common goals, and give everyone a direction to go.

And so to do that they've identified these five areas; technology developments; technology transfer. That's basically just, you know, we do a lot of R&D at the labs developing new types of energy storage, how do we actually turn that into commercial projects better. We don't have the best track record of that. Policy and valuation issues. Manufacturing and supply chain. And then workforce development.

And so there's a series of regional workshops you can see there. If you're interested and able to attend any of those, that would -- we would certainly welcome that. There will also be formal comment processes coming in the near future. And we're looking especially for the perspective of, you know, of regulators, of people who are directly involved in these proceedings to help us understand what kind of work should we be doing to better inform the information needs that you see.

And with that, I'm happy to take any lingering questions.

CHAIR MITCHELL: Thank you, Jeremy. Any questions for Jeremy before he hands it over? Questions from staff? Steve?

MR. MCDOWELL: The benefits that you were discussing that's from a revenue requirements perspective not necessarily from the utility's asset and earnings potential perspective, its revenues -- revenue requirements?

MR. TWITCHELL: So the cost side -- yes, the cost side is the revenue requirement for the asset to do the storage asset. And then the benefit side does include, you know, again, the time value --

MR. MCDOWELL: The alternative.

MR. TWITCHELL: -- of deferring the transmission line. And you can also have some other services there. Outage mitigation on the Island. They had poor reliability on the Island, and so this storage plus generation facility could mitigate some of that. There were some market benefits from regulation in the capacity market. Little ones, but -- yeah, so the cost side is revenue requirement. Benefits side are just all the market benefits, the deferral benefits.

MR. MCDOWELL: Are there any social costs, carbon or whatever included in that analysis?

MR. TWITCHELL: No. So our economics team is very disciplined and so they -- because we're working in this regulatory space, we only do the monetizable benefits.

MR. MCDOWELL: Yeah.

MR. TWITCHELL: So had this been some place like, you know, like California or somewhere where there were a means of benefiting or -- of capturing, monetizing some kind of carbon benefits potentially, but that was not something that was considered here.

MR. MCDOWELL: So the modeling that the -- that allows you to do this, it's -- it requires more extensive models and tools than traditional integrated resource planning functions. Can you speak to that any?

MR. TWITCHELL: Yeah. So IRPs are getting increasingly good at capturing all the generation-side benefits of energy storage. You know, I know Duke is actively exploring this space and improving their capacity and a lot of utilities are in that same boat.

The challenge here is that while we're getting increasingly good at modeling energy storage on the generation side, we have not done that on the transmission side. You know, despite all those rules and laws and policies I identified over the years, if you look at the transmission planning processes around the country, storage is just, it's not really on the radar.

So -- and that's because when we do

transmission planning, we're just looking at -- well, I shouldn't say just looking, but we're primarily focused on power flows and how does the power flow and where do we need reinforcement for the system, where do we need additional capacity for new resources, things like that. And so where there are benefits from doing a non-wires alternative or where there are potentially market benefits that could theoretically be captured, we don't have models generally that do that. And part of the problem is because we have that regulatory gap where, you know, I don't necessarily have a mechanism for capturing those generation-side benefits. Less of an issue, less of a challenge in a vertically integrated state, but still, still complicated.

MR. MCDOWELL: So in this analysis that's on the screen, what would cause them to be interested in finding an alternative to the additional wire? What was the impetus behind that?

MR. TWITCHELL: So mainly because of the way the transmission cost allocations would've worked in this place, that utility National Grid would've been solely responsible for building that wire. They couldn't have spread those costs out through the ISO.

And so for them it was just is there a way to do this that's less expensive than us building a third wire.

COMMISSIONER HUGHES: I think maybe where you are going, and I'm very curious, is the economic incentive modeling of particularly with a rate base versus who is going to recover and how do you incentivize innovation. Has your team looked at that kind of -- you know, from a utility's perspective where should they be spending research dollars because it would capture future economic benefit?

MR. TWITCHELL: So are you asking for storage in general or storage in this transmission case?

COMMISSIONER HUGHES: In your particular case. So, you know, weighing off what is going to be driving, you know, the market. I mean, just take for example innovation, you know, is the Company going to spend a lot of money researching storage that once they build the storage they're going to lose out on a significant rate of return for transmission that they would've otherwise built?

MR. TWITCHELL: Okay. Yeah. It's -- that is a really good question. And we actually -- I was actually at FERC last week having that same discussion as that's part of the challenge here is FERC and Congress for years have said, you know, there are these other alternatives that you should be considering in the transmission planning process. But we pay utilities to build things. We pay utilities to invest. And so, you know, you started to see kind of this move in the regulatory community to do performance-based ratemaking for utilities to kind of reduce or eliminate that incentive to build and own things. And there has been some discussion about, you know, maybe there will be a need for something like that on the transmission side to break that incentive for utilities, because you're absolute right.

In this case, you know, the stars aligned and it made sense, but this is an exception. The general rule is there. Under the general way we do things, there isn't a really clear incentive for utilities to look at non-wire alternatives and so that's why this is the exception and why we're hoping to lend a little more clarity to this space and maybe a little more information.

COMMISSIONER HUGHES: Just to be clear, I mean, I'm not sure this is the exception, because even though the utility was responsible, were they not allowed -- they weren't allowed to pass it onto the ISO, but were they allowed to pass it onto their own ratepayers?

MR. TWITCHELL: Yeah. I have to think they would have been.

COMMISSIONER HUGHES: Right. So then that's not an exception. That's actually a really good example.

MR. TWITCHELL: Well -- but, I mean -- but under most cases, you know, the utility -- there is no clear incentive for the utility to do this kind of analysis to look at this kind of alternative.

COMMISSIONER HUGHES: Yeah. And there wasn't in this case either. I mean, I'm just -- if I -- if I understand it, because the utility was able to pass on its cost, not that they would want --

MR. TWITCHELL: Yeah.

COMMISSIONER HUGHES: -- to do this and, you know, I'm not saying the utilities want to pass on cost to customers, but just from a pure economic standpoint --

MR. TWITCHELL: Right.

COMMISSIONER HUGHES: -- I just don't see the incentives from a utility perspective for this.

MR. TWITCHELL: Okay. And point taken. And I couldn't tell you what the point of decision was for the utility, why they chose to engage us to ask this question. I honestly couldn't tell you. But I agree that the economic incentives for utilities are such that this is unlikely.

COMMISSIONER HUGHES: Yeah. No. I mean, and I know you totally should look after the customers too, so I -- but just from a pure economic standpoint.

MR. TWITCHELL: Yeah. Yeah.

COMMISSIONER HUGHES: Okay.

CHAIR MITCHELL: Any additional questions? Kim.

MS. JONES: I would just offer up as you do your project looking for barriers to more of this and I might have the wrong one, but I think it was either FERC Order 888 or 889 some 20-odd years ago, basically told the electric utilities you need to separate your market function from your transmission function and I know when I was on the industry side, we didn't talk to each other --

MR. TWITCHELL: Right.

MS. JONES: -- and it was on purpose, because we didn't want to run afoul of FERC's kind of separation of duties policy and concerns about market manipulation, so --

MR. TWITCHELL: Well, it was illegal for you to talk to each other.

MS. JONES: Right.

MR. TWITCHELL: They --

MS. JONES: So we didn't do it.

MR. TWITCHELL: They've relaxed that a little bit now recognizing that there are some potential benefits in that coordination, but it's still a touchy space because they've said well, there are benefits, but you can't give your generation side an unfair advantage over other generators. So it's -- my understanding is the utilities are still trying to feel their way through that space, but FERC has relaxed it somewhat.

CHAIR MITCHELL: Okay. Looks like there are no more questions.

MR. TWITCHELL: All right.

CHAIR MITCHELL: Thank you, Mr. Twitchell.

MR. TWITCHELL: Thank you.

MR. PAISS: All right. Well, thank you for inviting me here as well. The topic that I'm going to be addressing is very different. It is really a safety discussion. And I'll just say that the topic of safety for a lot of people often isn't part of the initial equations, and with energy storage it's thrust itself in very unique manners. And so what I'm going to be covering here today is my role primarily is I'm a codes and standards geek. All right. I write a lot of the requirements that people that adopt codes and standards have to try and interpret and that's the challenge, is writing something so that somebody understands this is what they meant. Okay.

So PNNL has been very involved in energy storage codes and standards for a number of years and the impetus of that was DOE created an energy storage safety strategy about five years ago to help set the mark for research development for codes and standards to address potential issues.

And so, you know, these feed each other. You know a research will be done on a particular technology, it'll help guide the committees that are creating codes and standards, and those then need to be provided in some outreach and education to help users understand what those requirements are. And so these are kind of the three legs of the stools that PNNL's group is involved in.

So one of the objectives that I have as the lead on the safety codes and standards effort is one, being involved in the drafting of codes and standards, so I'm on a number of different committees; two, it's helping educate the users of those and understanding that there's a clear requirement for people to interpret. Interpretation is often a challenge with codes and standards, so we do a lot of outreach and education. And the ultimate goal is wide adoption of energy storage. It's very clear that this is going to be a massively adopted technology throughout the built environment.

So I'm going to just take a couple of slides -- I know that at the beginning of these discussions there was some explanation about basic technologies and chemistries. This will be a little, you know, review for that.

But in the different chemistries that are involved, one of them is flow batteries, and flow batteries is still very nascent in this space; however, it provides a lot of safety advantages that is driving its acceptance.

One of the more common ones is a vanadium redox. And, quite simply, flow batteries are two tanks of electrolyte flowing across a membrane as a fuel cell and there is no fire hazard with that technology. There's no stranded energy risk with that technology. Once a battery is turned off and the fluid drains out of that stack, there is no more power available. So those key safety points are really significant when we look at some of the other higher energy dense technologies.

That's one of the disadvantages with flow batteries is they're -- the energy density is much lower. You need a lot more square footage to get the same storage. But there are outdoor applications where that is not an issue where you have huge fields of solar, and flow batteries can be an excellent source of storage in those applications.

Duration is the other real interest. A lot of the uses for lithium-ion, you know, kind of stretch beyond four to six hours of duration, and so when we're looking at long duration storage, one of the technologies that is available today is flow batteries. All it takes is increasing the amount of electrolyte to increase your duration.

Another one is the cycle life. There is no degradation of the electrolyte. It's so valuable that some manufacturers just lease it, because there's a value stream in that electrolyte even at the end of the life of the battery itself. So that cycle life there is a significant selling point.

Now, when you get to lithium-ion, it is the highest energy dense chemistry available right now and there are a number of different chemistries within the lithium-ion family. The higher the energy density, the higher the potential volatility if something were to go wrong. So in this graphic right here, nickel manganese cobalt is one of the higher energy densities. Lithium cobalt oxide is a lower density. And as you go lower in the density, the safety increases.

So on the other side of the slide there, lithium iron phosphate is one of the lowest energy dense lithium-ion chemistries, but the other side of it is it has a higher safety feature. It's harder for it to get into thermal runaway. It can, but it takes a lot more energy. And then flow has none of those safety concerns.

So when we talk about safety, there's a number of ways that lithium-ion energy storage systems can fail and there's a variety of different failure modes. They can be exposed to thermal abuse, and that could come from either a poorly designed HVAC system, no HVAC, being exposed to very high heat environments or outside. There's electrical abuse, which is typically overcharging. Okay.

Rapid discharging or unbalancing of cells. One of the -- one of the key factors in maintaining battery safety is that they are charged and discharged evenly. If you had a large collection of cells and a couple of those cells were charged at a very high rate and the other ones were seen by the battery management system to be a low rate of charge and it's attempting to charge that entire model, these ones that are already charged higher could be damaged. So balancing is very critical.

Mechanical abuse. This is more of an issue in the manufacturing process, not as much of a concern as a Utility Commission, but people that are manufacturing products with batteries need to have a high threshold for safety from the batteries arrival in their facility to it being shipped out as a finished product.

Internal defects. These could be a low quality control of the cell manufacturer itself, a chemistry that perhaps degrades in a way that there could be internal defects created through multiple cycle life. These are often called dendrites. The quality of the separator between the anode and cathode that keeps these from shorting out.

And then environmental abuse. Seismic, flooding, again poorly designed HVAC. These are all potential failure modes that need to be considered in the procurement and design of a system.

When we talk about an actual fire, there is a common term used in the fire service and I came from the fire service, that's my background, and it's the fire tetrahedron. To put a fire out, you just have to take out one of those legs. It's either fuel, oxygen, or heat. Well, when we're talking about a lithium-ion battery, we're adding in another component; that's a chemical chain reaction. And now it's actually a fire tetrahedron.

And so to make this real simple, when we look at a lithium-ion battery that's gone into thermal runaway, some of these chemistries are creating their own oxygen in the process of that thermal runaway. There are metal oxides as part of some of these cathodes, so if you were to use a fire suppression system that is based on reducing the oxygen, it's not going to work with lithium-ion chemistries, because they can combust in the absence of oxygen. And then what you can then create is a high atmosphere of flammable gases now. So I'll get more into that, but that's one of the challenges with putting fires out with lithium-ion batteries.

So thermal runaway, that's not a term -- it's not a new term. You've all heard it. But basically it starts at heating and once the cell is raised up to a temperature 80 to 120 Celsius, the electrolyte and just a small amount of liquid electrolyte that's inside the cells it can become -- start to volatilize and aerosolize and build up a lot of pressure inside that cell. The cell at some point has to release that pressure, and the vapors that are coming out can be very flammable.

The heat that's generated from that cell can propagate to neighboring cells, and then you can have a kind of a cycle of heating, propagation, fire, and external flame production.

I don't think we have audio in this one here. Let me see if this is going to play. So this is actually a -- there are people sitting on this couch and this is a little scooter that's plugged in. So dad's getting up to unplug the scooter where a battery just popped.

Now, that's a pretty dramatic video. And let me answer both sides of the reactions here. There are manufacturers whose reaction is well, that's not a listed product. All right. That's not representative of the high level of safety in stationary energy storage systems. And I say to them you are a hundred percent accurate. All right. It's not a listed system. However, the cells that went into thermal runaway is the same chemistry that's put into the highest quality battery that's available today. So the potential of what we see there is there should cascading failures occur. Okay.

So I show this to point out a couple of different key points. One is the rate of gas release. The size of that battery in that scooter is probably 500 watt hours. All right. For example, a Tesla power wall going inside my home would be 14 kWh, much larger. Now, that's not to say that the Tesla power wall or any other manufacturers' battery would fail in that same manner. I just want people to understand what is potentially available and why the codes and standards are very important in these products.

So those gases that we saw released there is really a cocktail of a lot of different gases. The top gases there in gray are typically referred to as toxic gases and on the bottom are flammable gases with carbon monoxide being both. The majority of the gases released are hydrogen and carbon monoxide with about 30 percent of volume each. Both of those are very flammable and, hence, that's the concern with addressing the gas release if there is a failure.

So what I'm moving into now is for the responder community. You know, that's one of the questions that they have is should we have installations in our area. How should we respond to a failure? And most of the fire departments around the US operate on what they call standard operating procedures or standard operating guidelines and, you know, we have -- there's an example of one there from the London Fire Brigade that had to do with solar responses. I used to work on creating training for solar incidents around the country.

Anyways, so the key points that the codes are addressing for the response community is identifying what they want to have into their standard operating procedure; what the chemistry is; what the hazards of that particular chemistry. For example, a flow battery is going to have more of a caustic liquid release hazard, so containment and cleanup is going to be the issue. Something that's flammable is going to have different hazards.

When there is an incident the fire department needs to understand what they're responding to. We've had a couple of incidents in the country where when the fire department showed up, the experts on the scene which was either the manufacturer if it was an incident at an manufacturer's site, or the facility owner, they weren't quite clear what the hazards were with the batteries. It's still fairly early in this industry unfortunately. And so some of the information that was provided to the responders was not accurate.

So at the very beginning the fire department is going to want to determine if there is a life safety risk. Are these batteries installed in occupied buildings? Are they installed in a dedicated-use building where there is no life safety hazard? Very different risk profiles and response profiles for those.

Getting data from the battery is critical and this is one of the gap areas right now is being able to get data on the health of the battery.

What type of fire suppression system, if any, is involved? I mentioned earlier if you have a clean agent system, you might have an environment where you've depleted the oxygen -- and again, those clean agent systems work great on visible flame. So if you have fire in some wires, it'll work. If you have a thermal runaway, it won't work. And those gases can continue to be produced, so what you could actually have in that space is a very high flammability environment.

I'm going to talk about one event. This was the event that occurred in Arizona in April and it fed a lot of discussion of best practices that hopefully will make their way into the codes, but there is a long delay in codes.

The event that happened in April, the fire department was called by a bystander who was driving by and saw smoke and thought it was a grass fire. Fire department shows up to the substation, confirms it's not a grass fire but it is a fire in this battery enclosure. They knew it was a battery enclosure but didn't have a lot of other details. A representative from the utility showed up, confirmed that it was a lithium-ion battery, but didn't have a lot of other information. They took their time. They called in a hazmat unit and they did a lot of sampling. They were getting high levels of hydrogen cyanide outside the battery, so that was causing them some concern.

At the same time the utility was wanting to have their facility back. There was not any signs of significant smoke production anymore, so it was felt that the fire was out. But those high levels of cyanide were what kept the fire department from saying okay, it looks like it's out, we can leave, you can have it again.

So it was determined to do some more sampling, open the door and so some sampling. The door was open. This was three hours after the original event. And about two minutes after the door was open, there was an explosion.

This is an image of one of the hose lines inside the fence line. There was some smoke coming from some of the pad-mounted transformers there. Here's a picture of the building. Those are HVAC units on the outside. There was eight of them. And the fence which is about 20 feet away. This green mangled piece of metal was the door to the container, and when the explosion occurred, it was thrown off of its hinges out to the fence line. Significant amount of force to that door.

This is where two firefighters were stuffed underneath the fence and pushed another 50 feet away. The amount of force it took to push them was significant, and it stripped off a lot of their gear. This is where they landed, 73 feet away from the building.

And the -- why it's important to see these pictures is it's important to understand the force that was involved. It helps us to understand what took place in that explosion. It was a high deflagration rate. All right. A lot of carbon monoxide, potentially hydrogen as well.

And the key point here is that this is a system that was owned and operated by a utility remote from any, you know, civilians. Not a neighborhood substation, very remote and yet this occurred. So we'll talk a little bit about some of the best practices from this event.

There have been a number of other events around the world. South Korea had close to 30 fires in the last two years with energy storage systems from a variety of reasons; from poor design, inadequate HVAC design, BMS failures, battery management system, and overall systems control failure.

One of the commonalities in all of these systems was that they were not listed to UL 9540. Okay. 9540 is a product standard for stationary energy storage systems that I'll get into here. It was just released a couple of years ago, so some of these earlier systems didn't have the opportunity, but in other countries they might not follow that listing requirement.

So when we look at the overall standards and the model codes hierarchy, when we start at the building itself, there are a number of fire codes that address that. There's the International Fire Code, the NFPA 1 Fire Code, International Residential Code, building code, Fire and Life Safety Code. When you get down to the actual installation of the energy storage system, NFPA 855 is the newest standard. It was just released this year. And there is also on the utility side IEEE C2 or otherwise known as a National Electric Safety Code, NESC. There's a number of other documents. And also we have 9540A. That is a fire test method. And I'll talk a little bit more about that. And then NFPA 70 is the electric code.

So on the energy storage system itself, just the battery not how it's installed in the building, 9540 is the listing for the energy storage system. There is a thermal energy storage standard, the ASME TES-1, and NFPA 791 is the standard for unlisted equipment. So if you have something that you want to have field evaluated, that's what they would be guided by.

And we talk about the individual components that are involved, there's a bunch of UL standards that go into the products. 1973 would be a standard for a battery and a BMS. 1974 would be for the inverters. Let's see. I'm sorry. 1974 is for second-use batteries. 1741 is inverters. IEEE 1547 is the interconnection standard. So this is kind of a hierarchy of where these codes lie in these installations.

Now, when we talk about the fire code, North Carolina has adopted the 2015 fire code as part of their 2018 adoption process. It has very minimal provisions for energy storage systems as they live today. It was really designed around UPSs and light acid technology. It just talked about one or two hour fire rated separations, no hazmat requirements. There was some spill control. A little bit of ventilation requirements. The battery quantities are unlimited and the location in the buildings are not regulated. So when it comes to having codes and standards to protect you for energy storage safety, you have a real, you know, absence or a real gap in this state.

This shows what states are on which cycles, and the yellow is the 2015 fire code. The green is the 2012. The blue, the great state of Kansas, is still on the 2008, I believe. The 2018 fire code is only adopted in a couple of states. And California is going to be jumping forward and adopting the language in the 2021 fire code next year. Some states have the ability to bring forth future versions. Every state is a little bit different. The states that are gray are NFPA states and they adopt the NFPA 1 fire code.

So NFPA 855 I mentioned earlier, this is a standard on stationary energy storage systems, and it is probably the most advanced code on addressing stationary energy storage. However, utilities typically do not adopt NFPA standards. They guide themselves. They're self-regulated. Guide themselves by the NESC. Unfortunately, the NESC does not really address lithium-ion hazards. It's really, again, just for lead acid and it's more of a shall than a should document.

So looking forward to the 2018 version, there was a deep dive into lithium-ion hazards and there was some thresholds of when that code would take affect; basically 20 kWh. And it's a maximum allowable quantity 600 kWh, and that would kick you into another hazard class. Some size and spacing. We wanted to ensure that we're not putting too much energy too close together without there being some more studies that would guide the fire protection systems. And then the most important thing was they required a listing to 1973 or 9540.

So again, these are some of the threshold limits. The 2015 really addressed gallons or pounds. It doesn't really address the power and that was the appropriate unit of measurement. Pounds of lithium-ion was not -- it was not the right metric to use.

Maximum allowable quantities is what this means. I apologize for the acronym. In 2015, there is no maximum. For the 2018 code, it was 600 kW within the building. Again, if you wanted to exceed that or put them closer together, you needed to do large-scale fire testing and have that guide, the design of the fire protection system. That large-scale fire testing is now what's known as 9540.

So the requirement was a maximum of 50 kWh for an unlisted unit or 250 kWh for a 9540 listed unit. Then separated by three feet unless there was in that testing it showed that there was no propagation when the unit was put on fire.

This area of explosion protection as you probably have gathered from that little video I played earlier is a really key component that's in the 2018 fire code and NFP 855. We understood that the gas management is critical and there's two ways of meeting the intention of the code. Either allow deflagration venting, which in other words would direct an explosion to not damage the building and not be directed towards people, or through a ventilation system exhaust the gases before they got up to an explosive limit. So you could do one or the other in either the fire code or NFP 855.

So large-scale fire testing, again, these are the conditions it wouldn't be needed under; a larger unit size, closer together, or increasing the total amount. It has to be done -- the testing has to be done by a nationally recognized lab to a certain standard, which is now 9540. And the 2021 fire code specifies that it has to be 9540A. The 2018 fire code just says large-scale fire testing. It was prior to 9540 really being adopted widely.

So in the 2021 fire code, which is -- which will be published in I believe it's the fall or the summer of 2020, it adds operations and management to the requirements, retrofitting, commissioning. Essentially, the same language that's in 855 was put into the fire code. We really wanted to try and have some continuity between different code bodies. NFPA 855 will probably not be adopted by itself. It'll be adopted through reference through the IFC or NFPA 1. As a matter of fact, NFPA 1, the section on energy storage, is going to be basically erased and it's just going to point towards 855. So 855 really will be the key document for energy storage, and because it's published now and available now, states can point to it.

I understand the Utility Commission doesn't have the enforcement capabilities, but just letting you know of the gaps that exist here in this state and what's available.

So a little bit about 9540A test method. We really wanted to understand what happens when a battery fails and it catches fire. How big does the fire get? Can you control it and keep it from propagating to the rest of the entire battery system? And it's a very, very aggressive test that forces a battery into thermal runaway and it's done at a couple of different levels.

We start with the cell and they put the cell into thermal runaway to understand how much gases come out, what are those gas constituents, how much heat comes out. Then they do another test at the module level and they want to see do gases come out of these modules. And then they'll do the whole unit, the whole rack. And if fire comes out of that rack then, they then need to do what's called an installation level test, which would include any fire suppression systems that would be recommended for that. So it's a series of tests that are done all the way along.

For technologies that are -- that cannot go into thermal runaway, there is an offramp in the testing. So for example, flow batteries. The flow battery cell cannot go into thermal runaway, so it achieves its 9540 listing or at least the 9540A listing from the cell-level test. But there are other features of 9540. The construction, the communications that all batteries need to go through.

So it's really important to understand how the gases are released. And again, this is one of the challenges with lithium-ion today. There are technologies that are being worked on in the lab that do not demonstrate thermal runaway capabilities; however, they're still several years away from marketability.

Again, on the unit-level testing we're looking at what effect it would have on neighboring combustible services; walls, other units. So this is just a little diagram of how UL would conduct this test and then where they'd be measuring temperatures. No flaming outside the unit. Or if there is, it doesn't increase the wall temperature above a certain rise. So no explosion hazard observed. Maximum temperature on adjoining walls no more than 97 C above ambient temperature.

So one of the requirements is that energy storage systems cannot be put into habitable living spaces of a home. That might seem obvious based on the video, but there is a lot of people that would like to have resiliency down at the residential level. That is a big interest in California where we're experiencing the power safety shutdowns, and so the distributed generation and storage will occur at the residential level, and so those products, you know, having them be a safe technology installed in a safe location is of significant interest in California.

One of the challenges with the 9540A testing is in the past it had not had a pass/fail criteria. It would just generate a ream of data that then the AHJ was supposed to interpret and understand if that fire suppression system was adequate. And we advised you all that's not the best method, because a lot of AHJs don't have that technical expertise to do that, so now 9540A has pass/fail criteria in it. And all the AHJs would need to look at is that it has its 9540 listing.

So best practices. We've had some failures. We've had some codes developed. How are we doing with the alignment of those? There are some gaps and we were educated by the failures on these gaps.

Exterior marking and visible alarm enunciation is one of those that responding community wants to see. They want to know as they're pulling up what they're pulling up to.

Gas detection. All right. It's important to understand what is inside that facility and there is some challenges with typical gas detection and there are some new technologies that are being able to detect off gas of those cells at very, very early stages.

We're seeing some value in multiple-stage suppression. So the clean agent that I mentioned earlier, that in a sense could almost be creating a bomb in that facility if it's a sealed up room. So the best practices are now looking at utilizing if you want to use a clean agent system to catch a visible fire, that's fine, but a suppression system based on water has been shown to be the best agent for pulling the heat out and actually controlling that fire. Full extinguishment has been found to take a very long time, so these are very delayed and extended events.

Smoke and heat sensors. All right. The heat sensor is very important. If you're utilizing that clean agent and it doesn't put out the thermal runaway, we'll start to have an increase of heat again inside that room. It's important to understand that, so then you can then trigger the secondary system with water suppression.

An automatic exhaust system -- all right -- with the sprinkler activation. If you have a clean agent system, you need to seal that building up tight, so that that clean agent can do its job. But after it's designed soak time they call it and you're moving to your next agent those gases have to be dealt with. So one of the best practices that we're looking at is an automatic exhaust to trigger when the sprinkler system goes off as well as a manual option so that responders could ensure that it is being ventilated prior to anyone gaining access.

One of the -- one of the things that we hear quite a bit by utilities that want to put in a remote system is they'll say if it's on fire, let it burn. We don't want anyone to risk injury. We don't want the firefighters to go in and, you know, what I share with them is at some point somebody is going to go in there. How do you know when that is the right point? How much data are you getting to know that, you know, it's not a hazardous environment inside or the thermal runaway has stopped? So having the data from the battery management system from the environment inside is very important.

And this is what this bullet is talking about. The battery management system, if it is shut off at the first sign of a fire then you've lost communication with it. That was one of the problems that occurred in Arizona. Maintaining eyes on that condition for a very extended period of time is very important.

Currently battery management systems have no standard. They're all uniquely designed by the manufacturers to serve that battery. But as we know that there are very important safety features to keep that battery from getting too hot, overcharged, it's a safety feature, so it really has to have a standard. And there's two different standards that are being created right now that, you know, PNNL has staff working on it. But getting the data and maintaining an on-state for a long time is important.

Monitoring the temperature and the gas are very key metrics. Some batteries are designed to measure temperature within a module in multiple places. Some might only have two thermocouples on the outside of a module. So really getting good temperature data is -- it's not standardized.

When it comes to an incident, understanding where those locations are. Some fire departments know where these installations are. Some have not been shared from the local utilities. And so having that data shared with responders is very important.

The planning of multiple scenarios, desktop simulations is very important. Much better to have that as a desktop exercise than the first time the fire department ever saw that battery, knew anything about it was when there was smoke coming from the building towards an occupied high-risk structure nearby.

Clear signage of the hazards as well as contact information. This is something that utilities are pretty good at is maintaining a callback number, but having the fire department show up first and not knowing who the most qualified person to show up is one of those gaps. And the qualified persons when it comes to energy storage is another gap.

Fire department in New York is establishing a program. They have something called a white hat program. All of their high rises have one person that is trained in all of the building systems that responds to a designated location outside the building to liaison with the incident commander to assist them with that building's systems, and they are applying that same program to their energy storage systems that will eventually be in the high-rise buildings. They're not allowed yet in New York, but they will be soon.

So the priority, again, for the response community is life then property and then the environment. So rapid notification of 911 from, if it's a SCADA or control center, notifying 911 promptly is very important and has not happened always.

Determine if it's an evacuate or a shelter-in-place. Having the liaison work with the incident commander. Having that person who is that qualified knowledgeable individual is very important.

There have been incidents where that qualified person provided information to the fire department that said well, there's lithium in the barrier, you can't use water. And, you know, lithium metal is very different than lithium-ion. All right. The first one is a primary metal. The other one, lithium secondary metal is not water reactive and the quantities of lithium involved in the batteries is so small that it does not provide any kind of water reactive reaction, so water is the agent of choice.

Decommissioning and end of life is one of the land mines for this industry. It's easy to try and plan out a planned decommission. Let's say you know the product has a 10-year warranty and we will plan to pull all of that equipment out at the end of 10 years. When you have an unplanned decommissioning, that changes everything. And that is something that's very challenging because as was discovered in Arizona, when they had that fire their process of decommissioning those batteries took I want to say it was about six weeks and if that's occurring inside an occupied building, that business destruction is going to be pretty significant. So having that decommissioning plan include unplanned decommissions, it is very important.

Emergency energy discharge. I only put this up because this was one of the net results in Arizona after their incident. There was an emergency adoption of some code changes in the Phoenix Metro area which includes 26 other cities. And one of the provisions they put in their code was an emergency energy discharge and it basically stated that there shall be an ability to discharge the energy in an emergency.

Now, you can imagine if there was a burnt-up rack, that could be impossible to do, so the code itself is not great code. It's unenforceable. But the important point is understanding this is where communities responded after that. They did not want anybody else to suffer an injury, and so it is a marker for the industry to take heed of and they research manufacturers to plan for that.

And in California where we have very large wildfires, it's completely reasonable to discharge a battery back to the grid over a period of time. If it's a four-hour battery, maybe four hours; might be able to do it in two hours, but that's reasonable. If you have damage to one module, it's reasonable that every other rack in that room could discharge safely. So those are some of the design features that I think are really important to deal with the stranded energy issue.

And again, as Jeremy mentioned, all of our work is funded through the Office of Electricity, Department of Energy.

So I now open up for your questions.

COMMISSIONER McKISSICK: Thank you for the presentation. It was certainly interesting. I'm just curious. I mean, I do believe with this last component of your presentation, you discuss the UL 9540 and all the other certification requirements, are there certain firms out there now that are aware enough of what's going on that they are more preeminently qualified than others to be designing these energy storage facilities and making recommendations on storage types of capacity and what might be used in conjunction with particular systems?

MR. PAISS: So the answer is yes, there are definitely battery manufacturers that understand the hazards and are applying a lot more research to addressing the safety issue. One example might be we understand the gas issue when a cell goes into thermal runaway. If the cabinet that that battery is put in has a lot of voids to where those gases are hiding in that battery, you could have a good ventilation system, but it's not going to address those hidden spaces of high concentration. And so the top tier manufacturers are looking at everything down to the hidden void spaces in their cabinets.

There are manufacturers that are looking at suppressant systems. They recognize that a pendent sprinkler above a cabinet that might have a metal roof on it is not going to get water on that module buried at the bottom of that rack and they're looking at directing water so that it actually does what it -- but it is manufacturer by manufacturer trying to address it.

And I'll just --

COMMISSIONER McKISSICK: Go ahead.

MR. PAISS: -- one last point. The area that I think personally I have the most concern is the residential market, because that market is not driven by, you know, PPAs or our banks. It's driven by me as a homeowner who wants to have backup and I'm going to go after the cheapest battery there is. I'm personally not going to but that's what's going to drive that market. So the push to the bottom on price is going to bring products in that have maybe a little more margin, because they didn't spend it on R&D.

COMMISSIONER McKISSICK: I see. So -- but it's the manufacturers that are all doing it; there are no firms out there assisting with designing these installations that may not be driven simply by the manufacturer's objective to sell the equipment?

MR. PAISS: So companies like Underwriters Laboratories that's doing these 9540 tests, they are a wealth of knowledge about batteries that perform very poorly and batteries that perform very well into those tests. However, each of those relationships are proprietary --

COMMISSIONER McKISSICK: Sure.

MR. PAISS: -- so they can't then go and educate. So as a lab, one of the opportunities we have is to request funding from the Department of Energy for publicly available research and that is one of the efforts that we're trying to do and there is a very small amount of research available out there, but more is needed.

COMMISSIONER McKISSICK: Thank you.

MR. PAISS: Thank you.

CHAIR MITCHELL: Additional questions? Commissioner Hughes.

COMMISSIONER HUGHES: Thank you. Do you have any experience with how the insurance industry is dealing with these? You mentioned the residential market. And could you talk about that?

MR. PAISS: I can talk a little bit about it. It's not my area of expertise. There are insurers in this space and where their market is is in providing -- and you might even be able to speak better on this one here -- but they're providing that risk to that asset. It's -- so the asset is funded to perform a certain function at a certain rate. Should it not be able to do that the insurance will provide that gap. But the insurance industry is not -- they're not diving down to the level of looking at the fire safety component, the fire risk of it.

Do you have a -- so Munich RE -- there's a couple of companies that are working the space, but it's -- it's more of a performance guarantee than a safety overlap.

CHAIR MITCHELL: Commissioner Duffley.

COMMISSIONER DUFFLEY: If we could go to page 25 of your presentation.

MR. PAISS: Let's see. Let's go back. Which slide is that?

COMMISSIONER DUFFLEY: It's the one called 2018 IFC Explosion Protection.

MR. PAISS: I'm overdriving the clicker.

COMMISSIONER DUFFLEY: Yeah, you're almost there.

MR. PAISS: Yeah. Right there.

COMMISSIONER DUFFLEY: Right there.

MR. PAISS: Yes.

COMMISSIONER DUFFLEY: So between these two options of meeting the requirement, are they comparable with respect to cost and safety?

MR. PAISS: Good question. They're very different. So let's look at an installation that might be a container-based battery. It's a very common utility installation that can just deliver on site interconnected.

Because that container is in a sense a structure, people can go in and out, there is a door on it, you know, it's required to have some certain life-safety features to it. It's pretty straightforward to put out some deflagration vents on the top of those containers. Okay. That's a fairly simple design. But what it doesn't address is the build up of gases that could be stuck inside there. And so while it is only one of the options that's required by 855, there is a lot of us in the safety community that don't feel that's adequate to only provide that, because at some point somebody has to go inside.

So now when you look at what's involved in an NFPA 69 deflagration prevention system, that's a very challenging mission, because the requirements of that standard are that you have no more than 25 percent of the lower explosive limit of gases inside there.

Now, while that just sits out there as a number, the reality of ensuring that that does not take place inside there. Remember that video again. Look how fast those gases were produced, and that was from a very small battery. If you had a very large-scale thermal runaway, that fan would have to be pretty big. And so the realities of implementing that ventilation is easier said than done, but it's still the best direction to go on a safety aspect.

Now, Arizona again, one of the other changes they made in their code was that they require both of these requirements. You have to do -- you have to provide deflagration venting and deflagration prevention. And what that did with the strike of the pen is that made it almost impossible to put batteries inside existing buildings, because unless that battery room is on an exterior wall, it's very cost prohibitive.

Now, do I disagree with what they've done?

Not necessarily. I think, again, they have an experience that's guiding them to protect, you know, their constituents. So that's -- that needs to really advise the industry to address this problem.

Does that answer your question?

COMMISSIONER DUFFLEY: Yes. Thank you.

MR. PAISS: Thank you.

CHAIR MITCHELL: Kim.

MS. JONES: Well, this is like way outside my background, so if these questions don't make sense, bear with me. You talked about -- you have the slide of the map of the United States with the different colors showing that North Carolina, if I'm understanding it right, the version of the International Fire Code that's been adopted in North Carolina is a little bit stale. Am I taking that right?

MR. PAISS: Actually you're pretty consistent across the US. There's a lot of states still on the 2015 fire code.

MS. JONES: Okay.

MR. PAISS: Yeah.

MS. JONES: So we should feel okay about that?

MR. PAISS: Oh, no, not at all.

MS. JONES: All right. Well, help me out.

MR. PAISS: No. So as a member of a code committee, it is our wish that we have the same version of the code across the US. If there's any manufacturers in the room, they would be applauding right now, because they would like the same too. All right. That's not going to happen. So the best that we can do is educate to those areas that can have a voice in the adoption process to try and bring forth the most current version if not just for this section of the code. You know, the code is a big document. There's not necessarily significant changes every cycle to the entire code. But when it comes to energy storage, there are significant gaps between the 2015 and the 2021 fire code.

MS. JONES: And do you know who makes that decision here?

MR. PAISS: I am not that familiar in this state --

MS. JONES: Okay.

MR. PAISS: -- how that's made.

MS. JONES: Okay. That's fair. And then you went on to talk about --

MR. PAISS: Typically the state fire marshal is very involved in the final adoption, but some of the processes --

MS. JONES: Are difficult. Then in the slide following this one about NFPA 855, you said that was the most advanced code but utilities don't tend to rely on it, they tend to rely on the National Electric Safety Code.

MR. PAISS: Correct.

MS. JONES: So if you were God in this environment, would you require them to use this and what would be the mechanism for doing that?

MR. PAISS: So thank you for asking that question. This is a very timely and interesting discussion. When NFPA 855 was created, the scope was really for all stationary energy storage systems. The concern from the utilities is that they feel that they manage their risks adequately, that they have -- they have an obligation to provide power. So their level of safety and standard is they feel appropriate for their risks and they are not interested as a whole at being required to follow this standard from a financial, from a financial --

There's a lot of justifications that are raised on why they feel that they should not follow this. And one of the things that happened in the adoption -- not the adoption but the approval process of 855 through its final meeting at the NFPA conference, there's a technical committee, and the utility industry showed up with a lot of members to support an opposition to them being included in the scope. The net result was 855 was published, where it says scope it says reserved.

And so that's not great for anybody, because then it leaves it to the local AHJ, the Authority Having Jurisdiction, to determine whether to enforce it or not. And I happen to be the chair of the scope task group on 855 and I'm trying to get everybody to come together to find where appropriate exceptions are for the utility industry. And there are places where I think it is appropriate for them to be exempted from some of these requirements, but I do feel that this standard should not be a blank -- they should have a blanket exemption from the standard, because there are areas in there.

For example, if they were to say if it were a remote installation controlled by us behind a fence and we want it to burn, if it goes, that installation is essentially what we saw in Arizona. Okay. So maybe on that example the fire department should have been better educated. So there is room for improvement throughout the entire industry. But that remote installation might not be remote in 10 years. There could be housing or other commercial pushing up against it.

So at this time I think that it is appropriate that they do utilize it. And when I have had some discussions with some utilities that they are going to self-regulate themselves to 855, so -- long answer. I'm sorry.

MS. JONES: Thank you. Thank you.

CHAIR MITCHELL: Okay. Any additional questions? All right. Gentlemen, we appreciate your being here today and sharing this information with us. It's been very helpful and informative and perhaps we'll see you again at a future presentation. Thank you.

MR. TWITCHELL: Thank you.

MR. PAISS: Thank you.

(The proceedings were adjourned.)

C E R T I F I C A T E

I, KIM T. MITCHELL, DO HEREBY CERTIFY that the Proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the Proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

Kim T. Mitchell
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Kim T. Mitchell
Court Reporter II