Algorithms & Power Systems Architecture:

Using Historical Analysis to Envision a Sustainable Future

Oral History Project

Interviewee:	Robert (Bob) Cummings
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Abstract:

Robert (Bob) Cummings is president of Red Yucca Power Consulting, Inc. He begins this interview by describing his educational background and professional positions that eventually led to a senior role at the North American Electric Reliability Corporation for more than 23 years. He discusses at length his role in developing the interchange distribution calculator (IDC), a widely used tool to track the actual flow of power and compare it to contractual power trades. He explains that opening the grid in the 1990s to wholesale power generators that wheeled across multiple systems created significant challenges for operators. IDC tags each transaction with a unique ID covering its size, start time, end time, reserve provisions and so forth. He contrasts this with the contract path, which is different from actual power flow, and led in more than one instance to near outages. He notes that better telemetering

technology after 1992 made a difference, as did introduction of phasor measurement after 2004. He describes NERC's effort to hire a consortium to develop IDC. He discusses virtual power plants (VPP) and distributed energy resource management systems (DERMS). He describes industry adoption and an incident where he gave his computer to a utility so they could use IDC. He talks about working with the disturbance analysis group after the 2003 Northeast Blackout. He identifies standard PPRC, coming out of the event analysis, as the first non-core NERC standard. He talks about the need for faster data gathering and analysis, giving the example of the 2016 Blue Cut Fire, during which PMU measurements were too slow to see what was going on with inverter-based resources. He explains protection zones. In response to a question, he describes helping marketers in the 1990s, such as Enron and others, learn how power systems work. He speculates about algorithms that will be outdated in inverter-based systems. He talks about working with protection engineers from industry, but not from academia, but notes that may be changing today. In closing he urges young engineers entering the industry to "Learn the system" and "Question everything!"

Note regarding Transcript and Timestamps:

Timestamps appear in the transcript but may not align with the recording. Pauses and interruptions may have been removed and the overall length of the recording may be reduced.

Transcript:

Julie Cohn (00:00:13):

This is Julie Cohn. I'm conducting an interview with Bob, Robert Cummings, on January 17th, 2024, online. Daniel Molzahn, Mark Goldberg, Sairaj Dhople, and Rachel Harris are also participating in this interview and may ask questions. Mr. Cummings, during today's interview, we're especially interested in your early work on power system operations and planning, both during your years in the industry and with the North American Electric Reliability Corporation or NERC. But we're also interested in understanding how your contributions evolved into system standards. First, let's begin with some introductory questions and general background information about you. If you would, please describe your educational background and your professional positions in the field of power systems operation, planning, and reliability.

Bob Cummings (00:01:06):

I have a Bachelor of Science in Electrical engineering with a power systems specialty from Worcester Polytechnic Institute in Worcester, Massachusetts. I started my career at Central Vermont Public Service in their planning department and in support of their operations department. In 1981, I moved to New Mexico and went to work for Public Service Company New Mexico. Stayed five years in operations engineering. Myself and their very first AGC system were delivered on the same date in 1981. So, in 1989, I moved to the ECAR office, in Central Area Reliability Coordination Agreement, which was one of the NERC regions at the time. And that has since been pulled into Reliability First. Then in 1996, late 1996, I started my career, my 23-plus year career at NERC in Princeton. And in 2010, I moved from Princeton to Albuquerque and worked remotely. My entire team, which was the event analysis team at the time, was also remote, which was quite the interesting thing. But that's basically, since that I retired in 2020, I started Red Yucca Power Consulting as an LLC here in the state of New Mexico and do work for Sandia National Labs. Did some work for Dominion Virginia Power and continue to do some contract work for NERC.

Julie Cohn (00:03:03):

So, would you describe your position in the industry as one straddling the industrial and regulatory worlds?

Bob Cummings (00:03:11):

It was mostly the applications world, for the most part. And it wasn't until the mandatory standards came about in 2005 that I got involved in the standard side of it. Many of the things that we're going to talk about in the tagging industry, in the IDC, they were pre-mandatory standards. So, part of them became in place through FERC Order 888. And the other parts were just, everybody said, yeah, let's do this. So, it was sort of a consensus without, without the stick, at the time.

Julie Cohn (00:03:59):

So, during these years, what do you consider the most important technical problem or challenge that you tackled?

Bob Cummings (<u>00:04:08</u>):

The most important accomplishment really was the elimination of relay loadability as a contributory or causal factor in event analysis for system disturbances. But—

Julie Cohn (<u>00:04:26</u>):

Before you go on, can you explain what relay loadability is?

Bob Cummings (<u>00:04:31</u>):

So, what happens in a zone-three relay, it is reaching very far out. So, its settings are fairly low in relationship to the load bearing capability of that circuit. So, if you have a circuit that has an emergency rating of 150 megawatts, your, your relays have to be set well above 150 if they're going to act properly. But if they're set near 150, the relay can get confused with—between the load and the fault-duty and will actually trip the circuit. This was arguably the cause of the 1965 blackout in the Northeast. So—

Julie Cohn (<u>00:05:23</u>):

Thank you. And then when did you start thinking about this problem?

Bob Cummings (<u>00:05:28</u>):

I started thinking about it in 1965, but I started addressing it actively in 2003, immediately after I was one of the principals in the analysis of the 2003 blackout.

Julie Cohn (<u>00:05:44</u>):

So tell us—go ahead—

Bob Cummings (00:05:46):

I created the detailed sequence of events database. I worked on all of the relaying and transmission performance aspects, saw some things I never thought I'd see, including phase-shifting, pole-slipping. So, it got pretty crazy. Michigan at one point was loosely attached to Canada, and with a 120 KV circuit, and it slipped seven poles in one direction, then multiple poles in the other direction, before we lost the record. Because we didn't have continuous recordings. That was all theoretical while I was in school. And to actually see proof of it across an open circuit breaker was pretty mind boggling. But—

Julie Cohn (00:06:50):

I can imagine.

Bob Cummings (00:06:52):

The other things that I consider my main accomplishments as far as, doing, creation of the tagging system for power interchange tagging, and the interchange distribution calculator, and we can talk a good deal about that. Those were, those were, aspects of stuff that to this day is still, are still in use and will probably be in use for quite some time. So—

Julie Cohn (00:07:29):

We'd love to hear more about both of those topics. Which—or all three really—where would you like to?

Bob Cummings (00:07:38):

Well, when I—like I said, I arrived the same day as the original AGC system for Public Service in New Mexico. So, I had the great pleasure of learning how to write auto generation control filters and control parameters for some very large steam stations. This was in the early days where everything was all analog, and they finally got to a point of doing set points. So, you'd send a signal to the San Juan Generating Unit and say, "You have to put out this much power," and get to do all the testing, including the full load rejection tests for those generators for four in particular. So that was, that was a very interesting thing. And when I first moved to PNM, I had to learn of all about inter-area oscillations and system dynamics, which really weren't a major issue in Vermont.

(00:08:46):

So, you fast forward all, all the way through all of my work at ECAR, where I was the coordinator of several of their panels, which were technical analysis people, and some of them did the studies. And I got involved in area studies between MACC, ECAR, NPCC, MEN, and there are a number of super acronyms, MEN, VEM, MET, VST, et cetera. So, I did a lot of that. And when I first moved out to NERC, it was about— just about the inception of the concept of interchange tagging. Interchange tagging is essentially a way of keeping track of the disintegrated utilities and power marketers exchanging power. And so that's probably where I should show you the slides 'cause that really explains how that went. That'd be good. Sure. So let me share, going to get this working right. So, I don't know if this is the right one. Let's see. There we go. So, when FERC started down the path of open access, introduced the marketers to the equation. But many, many times the goes-into's never equaled the goes-outta's. So, this is just an example of one of the things that happened all the time is: Enron bought 150 from Con Ed, sold a hundred to Citizens, and sold 50 to Atlantic Electric. So therefore, they traded on 300 megawatts. No, but this is the real example of the push towards tagging. So ConEd sent all of these, sold power to all of these people here. Then on the PJM side, there were a number of other people that are over here. But none of this really added up correctly. So, the reporting did not equal—so, if we got an interface here, it was overloaded: how do you unwind this mess? This is what actually had happened. So ConEd sold to Enron who sold to Citizens, sold, sold some to Atlantic Electric. They also sold some to Catex and Aquila, and Morgan and Stanley, and EECI get involved in it. And so, the same amount of megawatts on both sides, but it's hell of a lot more complicated than just A to B. So, we went into the idea of having essentially an identification thing for the tag for each of the data piece, pieces of data.

(00:12:31):

So, this allowed it to get to a point where people could keep track of what was where. I often thought about this in terms of painting the megawatts. So, what we were doing is: marketer one sold to marketer two, marketer three, who sold back into these two Control Areas, and finally it shows up over here at marketer five and the final control area, the destination. So, you ended up being able to create a tag that contained all this information. So, it has the transaction size, the start and end time, reserve provisions, the sending and receiving Control Areas, transmission provisions, and a unique ID. So, this sort of made it like a phone number for that transaction. So, who gets the tag? Everybody gets the tag so that they can see it progressing through their system. And this is important, especially when you consider that many of the intervening companies charge tariffs for wheeling across their system.

(00:13:45):

And dealing with parallel flows. People don't think of it too often, but if I'm going to sell a thousand megawatts from New Jersey to TVA, a hundred of that is going to show up on the Michigan Ontario interface. It's just Kirchoff's law. But dealing with it in this fashion gets to make a real mess. So that's the basics of why we ended up doing tagging. Now, it started in the West as a paper tag that was then faxed to the individual companies. And that wore really thin, really fast. We decided that it should be used for figuring out what was going to flow where. So, we came up with the idea in December of '96. Ben Lee and Dave Nevius and I were talking about using transfer distribution factors for power transfers, generation transfers, and for determining where you might have an outage transfer. If a transmission line went out, where would it go? Where would the power go? It doesn't go to, go away. The load is still there. The generation was still there. So, we ended up creating those, creating the IDC, and it was essentially a very old concept of transfer distribution factors based on the topology of the system. And so, you didn't have to change it very much for dispatch changes, but if you had topology changes that could change the factors, then you had to make changes. But it became a pretty robust platform. And—

Julie Cohn (00:15:38):

What does IDC stand for?

Bob Cummings (00:15:41):

Interchange Distribution Calculator. So, this was a problem that was created by the concept of open access. But you ended up having everybody, the marketers, the transmission operators, the balancing authorities, and the Reliability Coordinators who were brand new to the scene. They all needed to know this information. And FERC looked at it and said, and they incorporated the idea into 888. So, it really pushed the creation of the IDC in the Eastern Interconnection. And later that enhanced curtailment calculator was adopted by the Western Interconnection in the WECC. How they ever got away from paying for their fair share of the development costs, I'll never know, <laugh> but it was pretty crazy. The—go ahead—

Julie Cohn (00:16:52):

Before you go on, I think Sairaj has a question.

Sairaj Dhople (00:16:57):

Yeah. Bob, this is quite interesting. I just wonder if you have an idea for what fraction of the power that is dispatched on a daily basis, or capacity of—I don't know how to quantify this, but what fraction do these interchange, or these bilateral transactions make up in the market? Is it, is it quite high? And has it been increasing since the time that you instituted these changes to tag these transactions?

Bob Cummings (00:17:28):

It has been very high. Virtually everything that passes through a marketer goes through this process. In, way back in history, the Control Areas - I would sell to you, you would split the savings economy A, economy B, and it was pretty straightforward, and the people involved in the wheeling. The other thing that I did do in my planning side, wide area planning side at PNM was, I did, worked on a Diné power project. And the power project was a 2000 megawatt, four-unit, mine-mouth, coal plant in the Bisti Badlands just south of Four Corners. And phase two would've ended up with two 500 KV lines from the Four Corners area into L.A. Basin. So that was the basics of it. But in doing that analysis, there were a couple of facts that we considered.

(00:18:35):

First of all, it was the natural, "I put the line in service what gets picked up by it, and what's its natural flow." The second part is the thing that you're hinting at, and that's called flowability. If I inject 500 megawatts at Four Corners, and the line goes all the way to McCullough, to the Las Vegas area, how much of the 500 megawatts shows up on the line in addition to the natural, natural carrying cap-capability. And the answer is, it's actually fairly small because of the number of parallel paths you—so you probably only get 30% flowability on the line that's intended to carry that. Contract path is not a great panacea, and it's not even a good a good thing for operating the system. In 1993, we tried to burn down Kentucky, and the way we did that was Tennessee decided not to start up 1500 megawatts of combustion turbines.

(00:19:52):

Instead, they bought power. They bought power from Com Ed in Chicago, who sold it to somebody in west of there, and they sold it to somebody south of there. And eventually it came through Arkansas and into Tennessee. But all the people who, in the middle, were getting hammered in Kentucky. And they got to a point where they had to open up lines, because they were just being overloaded, and they had no idea where it was coming from. So, that was one of my first forays into forensic analysis of power flows. But what we found out was this schedule had gone around the horn, but the actual flow was going straight from Kentucky. And unfortunately, it got the system into a condition where had they lost one 345 KV line in Virginia, the Eastern Interconnection would've collapsed. It was a very, very scary thing.

Julie Cohn (00:20:58):

What year was that? Do you remember?

Bob Cummings (00:21:00):

1993. July 22nd.

Julie Cohn (00:21:04):

You remember specifically? <laugh>

Bob Cummings (00:21:07):

Yeah, that's one of the things I do. <laugh> So, at any rate I hope that answers your question. Is it—it's you—you really do, what goes in at Ohio comes out, goes partially across upstate New York and back down to New Jersey. So, it's all over the place. You really do know—need to know where the power—if you inject it here, where is it going to flow to get to point B? So—

Daniel Molzahn (00:21:44):

And Bob, do you mind if I ask a follow up on this? Excuse me. Can you hear me okay? Sorry, this is Dan at Georgia Tech. So, you mentioned that folks would use switching that if these—if the flows were sort of going along, these loop flows in ways that that didn't work, then people would, would switch off lines. Was that common? I mean, was that kind of a one-off thing in this scenario, or did that happen frequently?

Bob Cummings (00:22:13):

No, that's not, that's not very frequent at all. As a matter of fact, they tried to hunt down what the cause of this flow was, and nobody had the catbird seat. This is prior to this formation of Reliability Coordinators. So, it was out there with the Control Areas. Now, in 1996, very similar situation appeared, but we had instituted the idea of Reliability Coordinators who have a bigger purview of the system, the bigger telemetry footprint. So, they could see, they could understand that they, that they were getting hammered by flows that were coming from Chicago, and—but—so they were able to take remedial action in the voltage, potential voltage collapse in Kentucky at the time. So—

Julie Cohn (00:23:19):

How much of this was a technology problem as well as an oversight problem?

Bob Cummings (00:23:29):

Part of it was the lack of knowledge of the transactions. So that became the technology that was then solved by the tagging in the Interchange Distribution Calculator. And the Interchange Distribution Calculator was then used by the Reliability Coordinator. So, the technology helped them to understand the flows. So, it sort of started one way, and ended up being the tools were built to mitigate the problem.

Julie Cohn (00:24:06):

But in the absence of the IDC, it was still possible to track the actual power flow?

Bob Cummings (00:24:13):

Yeah, because the telemetry was, increased the view of the, of the Reliability Coordinator. So, TVA was getting telemetry from Illinois, and they could see that power had come up in Illinois, and that it was coming from that general direction. It's much easier now with the, with the phasor measurement units. You can see it and you can see power swings very, very simply put, a whole lot better.

Julie Cohn (00:24:48):

Were there—

Bob Cummings (00:24:51):

But that didn't—the phasor measurement units weren't really put in service till 2004.

Julie Cohn (00:25:00):

So, were there ever instances where a utility would refrain from sharing its telemetry within an interconnected system?

Bob Cummings (00:25:09):

In the West.

Julie Cohn (00:25:10):

In the West?

Bob Cummings (00:25:11):

In the West, in the East, they had a universal operational data sharing agreement. And so that saved a lot of angst. In the West, they still, to this day, believe that their data is sacrosanct, and just really, it's theirs and nobody can have it. So, they have a thing called the Western Interconnection Data Sharing Agreement, WITSA. And it specifically prohibits the exchange of operational data, including, including phasor measurements. So, the only way the Reliability Coordinators can get those data is to: by going to all 22 Control Areas and getting signatures from each of the Control Areas that they can give this, and then they're not going to share it with anybody else. It's arcane and it's problematic, but that's what happens when the lawyers get involved. So—

Julie Cohn (00:26:23):

Did you want to tell us a little bit about the, a little bit more about the IDC?

Bob Cummings (00:26:31):

The IDC was an interesting animal. When we started, when, with the tagging realized that the faxing tags between the Control Areas really just wasn't going to cut it. And then this idea of using the distribution factors really won a lot of parts. So, NERC at the time did a solicitation, and had a number of bidders for the IDC creation and automatic tagging. And eventually a consortium of OATI, which is Open Access Technologies Incorporated, ATT, and Perot Systems won the bid. Eventually ATT dropped out, and Perot systems dropped out when they realized they could not get the data and repackage it and sell it, so they dropped out.

(00:27:57):

So OATI was created as a byproduct of building the IDC. We had an earlier IDC that was sort of, the cases were created by Ontario Hydro, and that operated for a year or two to help bridge the gap. But that whole thing was very different for NERC to be contracting for the creation of software. But it was all based on stuff that Bob, Ben Lee, and I, and Dave Nevius had done back in December of '96. And Ben and I came up with a team to work on it and just push it forward in January of ',97. So—

(00:28:53):

Other people involved in that were like Lou Loeffler and Don Benjamin, David—Dave—Nevis, and Mike Chen. They were all instrumental in getting that approved. But that went in service somewhere, I think it was in '98. And is still to my knowledge is still being used now. More recently, some of the concepts used there, and the distribution factors, are potentially resurfacing for use in the guideline, IEEE guideline for virtual power plants, using a nodal approach to understand where the power's going to come from when you say, I'm going to move this virtual power plant up, and to assure that you don't overload or cause, create, cause voltage problems or transient stability problems on the system. So, it's—I think parts of the <inaudible> end up resurfacing, and I think that's going to be a, probably the next step. But it's, like I said, it's old technology. It's just—the data is going to have to come from the virtual power plant aggregators and have to be working in concert with the distribution and transmission owner/operators. There's an entire IEEE guideline. IEEE is: 2030.11, which was about distribution, distributed energy resource management systems, DERMS.

(00:30:35):

So, there's work on VPPs as sort of an extension of that work. I'm a vice chair on that working group. And I was a vice chair on the DERMS working group, and on the inverter-based resources standard 2800-2022.

Julie Cohn (00:31:00):

So, NERC issued an RFP or a solicitation for companies to design a solution for this. Mm-Hmm. <Affirmative> tagging and following power flows. Two companies responded, both dropped out?

Bob Cummings (00:31:17):

No, there were actually several consortiums that applied for this—this particular consortium was awarded the contract. And eventually the two other partners dropped out. Perot Systems stayed around for, in an advisory administrative function for two or three years.

Julie Cohn (00:31:42):

Were any of the consortiums academic institution based?

Bob Cummings (00:31:46):

No, they were all, they were all entrepreneurs trying to come up with a way to do this. I found myself in an unenviable position of having to write a data dictionary for the registry database, because nobody else was doing it. <laugh> So I taught myself how to write a database key. Pretty strange.

Julie Cohn (00:32:16):

So, at the end of the day, it was in-house engineers who developed the calculator.

Bob Cummings (00:32:24):

Yeah, pretty much. We had Ben Lee from Ontario Hydro, John Tolo, with the tagging side of it. He was from Tucson. Myself, Lou Loeffler. And we were the engines, we were the movers and shakers. But there were a number of people throughout the industry that also contributed through the task force that was doing it.

Julie Cohn (00:32:51):

This was all prior to the Congressional Act that established the Federal Energy Regulatory Commission as the responsible entity for reliability on the grid. So presumably you had to enlist stakeholders either in the process or in the adoption of this. Can you talk a bit about that?

Bob Cummings (00:33:14):

That was, that was oddly enough, not a very hard sell, especially after some of the confusion that originally started with open access with the Order 888. So, it was pretty much mandated that we do this through, through order 888 in sort of a left-handed fashion. I mean, they didn't say, "Go do this." But it— the writing was on the wall that the industry was going to have to come together with a solution. We had the light bulb built, so the— it came together pretty quickly. I must admit that the arguments about who's going to pay for what during the development, and ongoing operation of the IDC were almost as complicated as the IDC itself, which was pretty crazy. But it was very useful.

Julie Cohn (00:34:22):

How was that part of it resolved? <laugh>

Bob Cummings (00:34:26):

Through a six-hour argument in Atlanta at an airport hotel. <laugh> And it was, the resolution was actually brokered by the president of ERCOT. He didn't have a dog in the hunt, so he acted as the intermediary, but it was pretty hot and heavy, sort of strange.

Julie Cohn (00:34:51):

Did ERCOT participate at all since they're out—? They just watched from the sidelines?

Bob Cummings (00:34:58):

Yep. Sat there chuckling and going, “we don't have that problem.” <laugh>

Julie Cohn (00:35:06):

Yeah, exactly. Do you have a question? Oh, so I wanted to back up again to what you were talking about a little bit earlier in the conversation about the relay loadability. Was there, what was the outcome of your work on that problem?

Bob Cummings (00:35:32):

Prior to the 2003 Blackout, NERC had a disturbance analysis working group, but it really wasn't relay-centric. And it became pretty apparent through our work on analyzing the 2003 Blackout, that one of the main causal factors, or one of the major contributing factors was indeed relay loadability a line tripping on zone three, and it really didn't need to. And when that particular 345 KV line tripped, the entire out-outage went dynamic, and there was nothing you could do to stop it at that point. But prior to that, for well over an hour, had you known, had you seen the phasor quantities—Had they been available—The system operators could have shed load in Cleveland and stopped it. But that was not existing, so we came up with a theory of angular separation theory.

(00:36:45):

Essentially, you could look at a phasor in Cleveland Basin [*Cleveland Bowl*], and using the reference at Browns Ferry, which is typical for the Eastern interconnection, you could actually watch the phase angle grow and grow and grow over an hour. So, during that time, we lost 24 circuits. Most of them by tree contact, except for the transformers. So, it was the mantra of the outage was: trees, tools, and training. But as a result of, we formed a handpicked group of protection engineers. There were 32 people involved. And our first meeting was in Chicago, in—I guess in July of the following year, 2004. And we had, we asked some pretty hard questions. We had—we initiated a review by all the companies of their relay settings. The relays were designed, so where would we possibly have relay loadability problems?

(00:38:04):

And then we had a mitigation plan that had to be put in place, and we followed that. So that task, that system protection task force, SPSCTF, was a controls task force too. It essentially got the industry to review, causing—, costing millions and millions of dollars, reviewing all of their relaying. And as a result, we found a lot of places on key circuits where this relay loadability could have been a problem. As a result, we codified it. By that time, 2005, we started writing standards. So, one of the first non-core standards was PRRC 23, which was a relay loadability standard.

(00:39:00):

And it got around the gauntlet of being one of the first non-core standards that came out of the policies of the operating manual in the planning policies prior to that. So, it—as a result, the tenets of PRC23 were implemented throughout the industry in North America and virtually eliminated the problem of relay loadability as a contributing factor to any disturbance. The one exception was in the San Diego event, the Pacific Southwest outage. There was a 138 KV line that hadn't been declared as a critical circuit. And—so it was never reviewed, but it had a relay loadability problem. And as a result, it put the nail in the coffin at the last minute. So, it was highly contributory. But again, it was just a matter of, it wasn't identified as a critical circuit. There are an awful lot of circuits in North America, so reviewing them all cost people a lot of money.

Julie Cohn (00:40:18):

Hmm. It's interesting to me that there was a relay setting that was the initial problem causing the 1965 blackout. And that was understood at that time. It had to do with, well, a mismatch between the relay setting and what the power lines could handle, as I understand it. But interesting to me that it took 40 years, roughly, to address that as an inherent problem in the grid.

Bob Cummings (00:40:53):

Yeah, exactly. And that's really just—there was no focus, and it would come and go, but it would be part of it. Every system, the '77 disturbance, '96 disturbance, everything else, it all—it happened, but it was never identified. The whole concept of how we look at event analysis, looking at the near misses, as well as the actual blackouts. If you wait for a blackout, you've got way too much to look at. If you look at the near misses, you start looking at: gee, that looks funny. And that's how you, we sort of kept on hammering on it. So, part of the problem was the, well, the Westwing outage of 2004, that was a single point of failure problem in system protection. So that echoed into other standards on single points of failure. But there, there came to pass a very, very large argument between NERC and the Nuclear Regulatory Commission, where they wouldn't let any nuclear plants, they weren't to review their, their single points of failure. And so that's another, another aspect that's ongoing. People know that's out there. They just don't, for some reason, don't want to, or think it's too expensive to fix.

Julie Cohn (00:42:44):

You touched somewhat on the fact that there was—there were changes in the electricity market when you talked about the entry of new generators and the wheeling of power over transmission lines. The 1990s were marked by market transitions in a number of ways. Were you concerned about grid stability as a result of the policy? Or were you focused more on observing activity on the grid and then discovering that there were problems?

Bob Cummings (00:43:18):

More on the latter. For instance, I found a pumped storage plant in Northern Michigan that, all of a sudden, instead of operating as a plant, was operating as individual units because the units were owned by different people. So, at any given point in time, you might have three units pumping, and three units generating. Made no sense. It just doesn't make any sense. So, when you start looking at problems like, of that nature, you start looking at loading problems, and then you get it, you fall into the: why is it protected that way? I—we know, but we ran a number of event analyses where the company would come back and say, "The protection system app operated exactly as designed." And I said, "Yeah, it did." But it was a real stupid design. That was a very common thing. So, the focus we brought to the system protection area, and our support of the Power System Relay Committee at IEEE, I think, really went a long way to improving the use of the system. That, and the implementation of phasor measurement, phasor measurements, of PMs, that sort of followed that. You could see things sooner than later. And, we were going along very nicely until the 2016 Blue Cut Fire, where we found out that PMU is way too slow to see what's going on with inverter-based resources.

Julie Cohn (00:45:14):

Oh, interesting.

Bob Cummings (00:45:16):

I never thought I'd say that, but we found that to be the case.

Julie Cohn (00:45:22):

So, I believe you said that PMUs were first adopted in 2004. Am I remembering that correctly?

Bob Cummings (00:45:29):

That's correct. That's when the Eastern Interconnection Phasor Project started EIPP. And that pretty much came out of the lack of vision from the 2003 blackout. But we got a lot of support in the Eastern Interconnection. And eventually we expanded it to be a North American phasor project. There had already been a WAM system, Wide Area Measurement system in the West. And it was interesting to bring. I, having worked in the West, understood and could see the benefit of the WAMS project. And then bringing that knowledge base into the Eastern Interconnection project was really helpful. But today there—you—the area coordinators, Reliability Coordinators pretty much can't live without having their PMUs. They've got to be able to see what's going on. So, for instance, we broke apart peak Reliability Coordinator and distributed it over five different Reliability Coordinators.

(00:46:53):

But when the harsh reality is in the West, if you were sitting in Denver, Colorado, you had damn well better be knowing what's going on the West Coast, the flows north to south, because if something goes wrong, all that power's going to be rushing through you. And we found in 1984, February 29th, 1984, that's a Leap Year Day, that there was a thing called the Grizzly Transfer Trip, and it wasn't activated. And as a result, when the AC lines on the West Coast tripped, all that power came rushing through around the east side of the donut. And when I thank my lucky stars, we had a good operator on our generation desk 'cause he took the—he took San Juan Station, he took it off of AGC and put it on flat frequency control. And the plant ran, rode through it, but we broke the West into three different parts when that happened. So—

Julie Cohn (00:48:08):

What ... oh, go ahead.

Bob Cummings (00:48:10):

The thing, Julie, is in my career, I got enough chance to see a problem and find that something else we came up with for solutions to <inaudible> worked fine to fix that other problem. So it was, that was one of the things that I was able to do with my catbird seat. And having worked in both the Eastern and Western Interconnections, I could see where they needed to know in the East, and, for instance, what is an eigenvalue, you need to know that if you're going to play in the, in the system dynamics game, into area oscillations game, you need to know, that's going to tell you what units are oscillating against what other units. So—

Julie Cohn (00:49:05):

That's an interesting perspective on problem-solving, that you have a grab bag of solutions based on past problems that were different in definition, but you're able to apply them. Were there any dead ends or major missteps in your experiences along those lines?

Bob Cummings (00:49:29):

Yeah, there was my knowledge of rotating machine and its behavior under faults, local faults, led me to the wrong conclusions on what turned out to be a phase jump based on the actual measurement of the phase angle in a PMU. So, we've now since corrected that problem, and we addressed that in P2800, we address it in all of the rest of the inverter-based resource work. You have to block any action taken by a phase jump. So—and the best way to think of phase jump is if I've got two phases in, 120 degrees apart, if there's a fault, they might get closer together. So that's the jump from the phase angle. So, the fault happens, it goes one way, and when the fault releases, it goes the other way. And that jump can be misinterpreted by computers. And that's what inverter-based resource coupling is, it's all computer controller. And I see a number of vendors go, I can do that in 10 milliseconds. I can do that in five. Sometimes fast is too fast, especially when you're dealing with rotating machinery.

Julie Cohn (00:51:05):

I have a few questions that ask you to look ahead a little bit, but before I go to those, Dan or Sairaj, would you like to ask any other questions or make any comments related to what Mr. Cummings has shared with us so far?

Daniel Molzahn (00:51:23):

Yeah, so I want to say first—thanks Bob. This has been really, really interesting. One, or a couple questions I had were: so early in the conversation you were talking about changing relays on circuits that were declared critical, how do you identify which circuits were, were considered critical and which ones weren't? And how did that decision-making process work out?

Bob Cummings (00:51:47):

Well, different people use different criteria. I had always worked on the idea of, if I take this circuit out, what is the largest single hazard from a transmission standpoint between point A and point B. If I take this circuit out, the strength of that circuit and the strength of that interface is determined by the other circuits to remain after that one leaves. So, if this one overloads the other two lines, then it's a critical circuit. And so too are the other two lines that it overloads. So, you don't want to have that happen, 'cause that's essentially what happened in Canada during the '65 blackout. They lost the line, and then by first law, the power flow got distributed onto the parallel lines. And those lines had to deploy the ones with the relay loadability issue.

Daniel Molzahn (00:52:46):

It was that common across—was that basically what everyone did or were there kind of different approaches to doing that?

Bob Cummings (00:52:55):

Well, it—the concept is overlapping zones of protection. Zone one is very close in zone two, maybe reaches out to the other end of the line, zone three maybe goes beyond that. So, knowing what you need to know about how that line is going to perform in the content of the system is the important part. Now this is one of those situations, well, while we're working on the 2003 blackout, there was a young engineer at Eastern Pennsylvania Company who was putting some new relays, digital relays, in service. And he called one of our participating engineers and said, what should I use for the zone three settings? <laugh> It was a resounding: don't you ever use zone three settings on those relays! <laugh> So it's—why did they do it? Why did kids put beans in their ears? 'Cause they could. <laugh> And that's what it really boiled down to. But the—you determine which circuits can cause problems. So, in your transfer paths, you—different circuits and some are going to rise to be the most important circuits. And after you get down through about five or six layers, you realize that I don't have any more. Everything else becomes immediately important. Well, yeah. When you've lost five circuits, it's like that.

Daniel Molzahn (00:54:44):

Got it. No, that's really interesting. Thanks. Thanks for sharing the story. I had a couple other questions going back further in the conversation as well. One was related to the, your, your power transfer distribution factor approach and the sort of loop flow issues. One question that I've always been curious about in that context is, how do you manage, or how do you account for line losses in that—in those calculations? I know that's probably relatively small, and so I'm wondering, did you just neglect that or—so I cause flows through my neighbor system, who pays for that or how’s—?

Bob Cummings (00:55:20):

That was, that was not a you-pay-for-it issue at the time. So, the distribution factor just really says this much additional flow is going to show up on that circuit. Now, unless somebody was sitting around doing loss calculations for that circuit, they weren't going to ever see it. For the most part. It's small.

Daniel Molzahn (00:55:46):

It just was small enough that no one really got too concerned. Is that kind of a—

Bob Cummings (00:55:50):

That's correct. Now depending on the tariffs that were used for transfers, wheeling transfers, I might put in 95 megawatts at point A, and you get to pull out 90 megawatts at the other end. And the other part is—has been—already calculated to be the losses on that circuit. So that happened, but it was not included in the IDC itself. The injection was the key, the sending in.

Daniel Molzahn (00:56:31):

Got it. I see. That makes sense. And I guess the last question I had before, maybe turn it over to Rachel or Sairaj if, if they have other questions, is: so, you were kind of, again, in the setting, you were putting in place the IDC, you were taking these transactions. I mean, I suspect there was a lot going on <laugh> at the time. How did you sort of ed—was there sort of an active education campaign that you were trying to explain to these power marketers that, "Hey, you can't just put power in here, take it out there and it doesn't nicely flow along the path you want it to." Like, how did that—what—was there a convincing process you were doing? Or how did you—what did that look like in the industry with all these new players coming in at the time?

Bob Cummings (00:57:19):

Well, the new players would come to your doorstep and say, "Please, can I do this?" And if you, the operator of that transmission system says, "Yeah, you can do that, but you got to do it this way." So it was, it was an inherent piecemeal learning process. And so, you had large, large marketers, like Enron and such, that they learned pretty quickly where they could get away with what, but for the most part, everybody wanted to get on the block. And so, they were willing to whatever needed to be done, so—

Daniel Molzahn (00:58:08):

And so, did you—was NERC—and in your role, were, were you trying to explain this to people, or you said, you said, the marketers kind of figured it out. They just—well—

Bob Cummings (00:58:18):

We made, I can't tell you how many times I crisscrossed the country going to different meetings in different regions, doing presentations on the IDC, or on the tagging. There was one, there was one in the early days of tagging where the people from New York, wasn't an ISO yet, but they said, well, we don't have any computer that can do that. And I closed my computer and I handed it to them. I said, here, now you do. Yeah. You, you, you had to sort of hit some people over there with a stick in order to get them to understand that this is the way it was going to work and not doing it that way was not going to work.

Julie Cohn (00:59:06):

That add leads me to a question about the IDC. Was it platform-agnostic regarding computer systems?

Bob Cummings (00:59:17):

It could be, but it was initially run, the interim IDC was run by Ontario Hydro, that eventually stood up at OATI. OATI did multiple things. They created platform interfaces to EMS systems. And so, they made, they automated a great deal with it. But it pretty much was: You build, once you build the base case, and you calculate the factors, it didn't matter. You could do it on a, on a laptop at 35,000 feet. You're just dealing with a distribution-driven matrix.

Julie Cohn (01:00:01):

Yeah. So, it lived on the internet essentially?

Bob Cummings (01:00:04):

No, not. Well, it did, it depended on the internet, but it was, it was actually a piece of hardware. There was no cloud computing.

Julie Cohn (01:00:14):

Yeah, yeah. The exchange of data took place across the internet.

Bob Cummings (01:00:19):

Yep, yep. And—we had to limit the amount of size. So, the transaction that had to be tagged, had to be greater than three to five megawatts at different times. We had different values. But the result from the marketers was, I'm going to break my—a hundred megawatts into twenty different 5-megawatt pieces so that you never see it. <laugh>

Julie Cohn (01:00:47):

Wow.

Bob Cummings (01:00:50):

And it's like, why, why is there a 99 KV system in Imperial Irrigation District? Because the common knowledge was anything above a hundred KV was going to be subject to standards, and penalties.

Julie Cohn (01:01:08):

Interesting. Intersection of the marketplace and technology. <laugh>

Bob Cummings (01:01:13):

Yeah.

Julie Cohn (01:01:16):

Sairaj, did you have any additional questions you wanted to ask at this point?

Sairaj Dhople (01:01:20):

Yeah, a —just a more general one, but perhaps following up on what Dan was inquiring about as well. Over the years, Bob, you've interacted with stakeholders from many different types of industry and across different sectors of—engineers that have cared about the power grid. Have you seen these interactions and these types of engagements get easier with time? Or have they gotten more challenging with time? And what does that say about our regulatory landscape and the types of technologies that we are trying to deploy on the grid today?

Bob Cummings (01:01:57):

Well, if you read my article that's in the PES magazine from last May/June, one of my reviewers commented to me, he said it was a really interesting article, but at the end it got very repetitive. And I said, that's because we keep on seeing the same damn problems again and again and again. So, what's happened is we've, we've had alerts to the industry, problems with inverters, and we're still having the same problem with inverters. Some in different places, some in Texas, some in other places. But that's—it's the same problem, because people aren't following through on the recommendations. And so, nobody has been having a desire to codify this into standards. And the IEEE standard is much different for transmission-based inverter-based resources than it is for rooftop solar. And people always ask me, well, how come you are worried about rooftop solar now? One, there was one or 200 of them, there was nothing. There were 16 million of them. It's a problem. These common modes of failure, common modes of tripping, and everything. So, but the third-party generator, third-party resource, batteries, and everybody wants to do things without doing the homework. So that's gotten tougher.

Julie Cohn (01:03:57):

Are there particular standards that were efficacious on a grid dominated by spinning turbines that really need to be reexamined as we increasingly add IBRs?

Bob Cummings (01:04:14):

Yep. There's a list that has been produced by the IRP, the Integrated Resource Subcommittee of NERC. And they identified a number of the NERC standards that need to be updated. When we did PRC2, which was, how do you measure the data? Well, the measurements were originally PMUs used, but most of it was high-speed data collection for plants above 500 megawatts. Well, you're not going to have a lot, a lot of 500 megawatt plants. You're going to have a 20–30-megawatt solar farm or wind farm. So, you've got to completely rewrite that standard so that you actually get the data. And oh, the higher speed units are truly needed. Most of the IBR disturbances in the last 10 years have been woefully lacking in high-speed data.

(01:05:28):

So, when I—we were talking about the necessity to have PMUs at certain generators, and I got a call from the generator forum, and the guy was saying, "This is costing a lot of money to put all this equipment in." So, I asked him, I said, "You got an 800-megawatt coal unit. If it goes, if it trips unnecessarily, how long does it take you to get back online and how much lost opportunity cost you have?" And it's—it sort of dwarfed it. It made the PMU installation a very small fraction of that number. So, for one outage that he couldn't explain, he lost a lot of money.

Julie Cohn (01:06:16):

Yeah. Over the course of a hundred years, there were various initiatives to establish some sort of federal role overseeing the power system, most of which didn't get anywhere until 2003. And I just now wonder, how important was it that we finally had technologies to measure what was happening across the country to make federal regulation efficacious?

Bob Cummings (01:06:48):

Well, I think the introduction of the market, the open access aspects, we were able to, just in time, get something that could help us manage that system in place. But we—for a hundred years, we dealt with inter-area oscillations or machine oscillations. They're governed by the laws of physics of a rotating machine. So anymore, an inverter, it doesn't care what frequency you want to oscillate at. It, do it for any, any frequency. It might do it at 30 hertz, it might do it for 12 hertz. But you knew, with the rotating machines, anything below 1.2 hertz was a, in a machine oscillation. Not anymore. So, tell me, tell me what the Western Interconnection, inter-area oscillatory behavior is going to be next year. And you've retired all these coal units and you've been putting all these wind farms and solar and batteries, that they don't care what frequency they oscillate at. So, rotating—What's the next frequency that's going to be the problem? So, we're looking at the known frequency oscillations, but that's a crap shoot because you're looking at the wrong place. It's like sitting on a dirt road with a radar gun, you're not going to be looking at the right place to see the speeder. So—

Julie Cohn (01:08:36):

Sairaj and Dan, I have a very general question that I will close with, and Sairaj has his usual final question, but I wonder if there are any more related to technology, Mr. Cummings' experiences in the industry, in the regulator's world, and so forth that you'd like to share or ask at this time?

Daniel Molzahn (01:09:00):

So, Rachel had a question here, or a few questions.

Rachel Harris (01:09:03):

Yeah. Hi, this is Rachel. I'm one of Dan Molzahn's PhD students. So, I thought it was interesting you said it was pretty easy to get industry to adopt the IDC. Like they really recognized how important it was, and it wasn't a hard sell. Were there other changes being pushed out by NERC for reliability purposes that were more of a hard sell, that received more pushback from industry throughout your career there?

Bob Cummings (01:09:33):

There was—in the early parts of the IDC and tagging and all—we came up with an idea for a transaction management system, TMS. We held a symposium on it in Denver, Colorado. That was coolly received.

Ironically every tenet of that management system has been duplicated, and custom installations and at every ISO, RTO, and Reliability Coordinator across North America. And I mean it, the cost of doing that was enormous compared to what we originally thought we would be—could get away with. So, and a lot of that was just, they didn't want us to do it.

Rachel Harris (01:10:32):

Interesting. Interesting. I see. I had another, another question that I had written down. When you were talking about the relay loadability problem, you were investigating, and you pulled together this force of protection engineers to look at this. Were those protection engineers coming from universities or from industry or a mix? What was, sort of, the makeup of that group?

Bob Cummings (01:11:03):

It was all from industry. These were all—these were all real, real-time practitioners. Some were old school, electromechanical relay gurus. Others were new school, what today are known as teenage relays. Digital relays. Even in their early years of digital relays, they didn't have the current-carrying capability to operate on, to operate the breaker trip points. So, they had to have an entirely separate set of auxiliary relays that would be triggered by the, a digital relay, which would actually trip the breaker. So that's that. Slowly but surely to all the relays, the digital relays installed in the early nineties were teenage relays.

Rachel Harris (01:12:01):

Hmm. Cool. Thank you. Great. Yeah, those were just a couple. Oh, go ahead.

Bob Cummings (01:12:08):

They were, they were an amazing group of protection engineers, most, most of them were on the IEEE Power System Relay Committee. But none of them had ever, ever done anything in the NERC realm. So, they didn't know what to make of this guy from NERC talking relays to them. <laugh> It was pretty funny.

Julie Cohn (01:12:34):

Did it seem that there was a wall between academic electrical engineers and the industry and the regulator?

Bob Cummings (01:12:44):

I don't know if there was a wall. It was just a—you wanted to have the practical applier of a relay, be the guy who's writing the rules for the relay. I mean, there are—today there are an awful lot of very smart academic people who are very knowledgeable in the system protection side of this. They're the ones who came up with the hardware in the loop concepts, and test beds of that nature. So, if we were doing it today, we'd have a very different complexion of that group.

Daniel Molzahn (01:13:32):

Maybe one sorry, Julie, maybe one follow-up question on that is: do—so not necessarily just in terms of different academic versus industry, but also in terms of different roles—are you seeing these teams get more diverse in terms of expertise, that you're seeing protection engineers and combining with more transmission planners? Are you seeing sort of larger teams to tackle these emerging issues? Or is it still reasonably siloed?

Bob Cummings (01:14:04):

It's somewhat still siloed, but the protection side of it has gotten a lot more, not, a lot more, a lot thicker, let's put it that way. The universities are teaching more protection theory, Arun Phadke at Virginia Tech and they're just—they're the gurus and they're teaching it. So, we still have the problem of the myopic view of the graduate student who comes in, and I'm going to take over the world in five years. But what do you know? I know everything there is to know about this little piece of thing that I wrote my master's and doctorate theses on. And the company hires them to look at that. They don't look at the big picture anymore. They don't have that breadth of experience, which is sad.

Julie Cohn (01:15:10):

If, well, this is probably a fitting moment for Sairaj to ask the question He often asks at the end of these interviews, and then I'll follow with my final question.

Bob Cummings (01:15:20):

Okay.

Sairaj Dhople (01:15:21):

Yeah, Bob, just—our, our listeners here are probably going to be future students and engineers who are interested in entering the industry. Any words of advice for our next generation of power engineers from someone who's been there and seen it all?

Bob Cummings (01:15:40):

Learn. Learn the system. Question everything. Learn about the system. Ask questions. There's—nothing happens by sympathy; there are no sympathy trips. There's a reason that really operated. There's a reason that generator tripped. You need to get down to the basics on that. That is the one thing that you need to do. The other thing is: any student really needs to walk out of a university knowing how to run a powerful OM system dynamic study. There's a lot of them who don't even know what PSSE and PTI are. And they're operating in systems that aren't used in the industry. And so, there's a very heavy-duty rise time and everybody has to be retrained. So—

Julie Cohn (01:16:41):

Thank you. And more broadly speaking, if you had a chance to educate the general public about what your work has been and why it was important, what would you want them to know?

Bob Cummings (01:16:55):

I would want them to know that I'm a student of the system. I'll let the system tell me how it's going to behave and I learn from it. And then I use its characteristics to my advantage and not try and—the laws of physics. That's the bottom line. I—in a way, I'm sad that I've retired because there's so much fun stuff going on these days. I'm sure your dad felt the same way when he retired.

Julie Cohn (01:17:31):

Yep. Well, thank you so much. This has been a really interesting and insightful and thought-provoking interview. We really appreciate your time, and your assistance with our project.

Bob Cummings (01:17:44):

Well, thank you very much for the opportunity. I hope—I did a number of talks at different graduate courses across the country. And if I managed to get one or two engineers in that, my career, to go into the power industry and really be serious about it; I was successful, so —

Julie Cohn (01:18:14):

Great. Thank you.

[End of interview]