CPUC Docket: A.16-09-001

Witnesses: Paul Alvarez and
Dennis Stephens

Exhibit: TURN-06

PREPARED TESTIMONY OF

PAUL ALVAREZ AND DENNIS STEPHENS

TESTIMONY REGARDING SCE GRC T&D Chapter, Volumes 3) System Planning; 6) Substation Construction and Maintenance; and 10) Grid Modernization (DER-related Components)

Submitted on Behalf of

THE UTILITY REFORM NETWORK

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May 2, 2017

DIRECT TESTIMONY

OF

PAUL J. ALVAREZ AND DENNIS STEPHENS ON BEHALF OF

THE UTILITY REFORM NETWORK

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DIRECT TESTIMONY OF

PAUL J. ALVAREZ AND DENNIS STEPHENS ON BEHALF OF TURN

I. INTRODUCTIONS

Q. PLEASE STATE YOUR FULL NAMES AND BUSINESS ADDRESSES.

A. Paul J. Alvarez and Dennis Stephens. The business we work for is served by Post Office Box 150963, Lakewood, Colorado, 80215.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. (Alvarez)

I am the President of the Wired Group, a consultancy specializing in distribution utility performance and value creation.

(Stephens)

I work for the Wired Group as a Senior Technical Consultant, where I specialize in helping clients understand and apply electric distribution grid concepts, technologies, and business processes.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. (Alvarez)

We are testifying on behalf of The Utility Reform Network ("TURN") regarding certain components of the Transmission and Distribution Chapter (2), generally those that are potentially impacted by the growth of Distributed Energy Resources (DER). Specifically, we are addressing Volumes 3 (System Planning), 6 (Substation Construction and Maintenance), and 10 (Grid Modernization, DER-related components). We recommend that the Commission reject significant components of investments the Company claims are required to accommodate anticipated DER increases, resulting in disallowances of $527.8 million in capital in 2018 and $1.6774 billion in capital from 2018-2020, as detailed by Volume in Table 3. TURN witness Garrick Jones will address recommended disallowances in Volume 10 related to Worst Circuit Rehabilitation (WCR), while TURN witness Marcel Hawiger will address policy issues raised by the Company's T&D proposals. TURN witness Eric Borden will address R&D projects related to Grid Modernization (Volume 11).

It is important to note we agree DER can provide value to the Company's customers, and we recognize that some increases in grid capabilities and some changes to grid operations are required to reliably accommodate anticipated DER increases. However, we observe that many of the Company's capital proposals are the result of exaggerated risks, rewards, or requirements. We also observe that the Company proposes capabilities whose incremental costs are dramatically out of proportion to incremental benefits, and that the Company failed to consider lower-cost, lower-risk alternatives available to deliver the grid capabilities we agree will be needed to reliably accommodate increases in DER. These observations will be supported throughout our testimony.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUNDS.

A. (Alvarez)

My career in the electric utility industry began 16 years ago with Xcel Energy, one of the largest investor-owned utilities in the U.S. After a series of product management roles of progressive responsibility for large corporations, including Motorola's Communications Division (now owned by Google), Baxter Healthcare, Searle Pharmaceuticals, and Walgreens, I served Xcel Energy as product development manager. In this role I oversaw the development of new energy efficiency and demand response programs for residential and commercial and industrial customers, as well as programs in support of voluntary renewable energy purchases and renewable portfolio standard compliance.

In 2008 I left Xcel Energy to establish a utility practice for MetaVu, a boutique sustainability consulting, where I utilized my M & V experience to lead comprehensive, unbiased performance evaluations of two full smart grid deployments (including both smart meters and grid modernization). To my knowledge these are the only two such post-deployment evaluations completed to date. The results of both were part of regulatory proceedings in the public domain, including an evaluation of the SmartGridCity™ deployment in Boulder, Colorado for Xcel Energy in 2010,[1] and an evaluation of Duke

[1] *SmartGridCity™ Demonstration Project Evaluation Summary*. Exhibit MGL-1 to the testimony of Michael G. Lamb in the Matter of the Public Service Company of Colorado Application for Approval of SmartGridCity Cost Recovery. Filed with the Colorado PUC in 11A-1001E on December 14, 2011. Alvarez et al. Report dated October 21, 2011.

Energy's Cincinnati deployment for the Ohio Public Utilities Commission in 2011.[2] My teams' findings concerning the smart meter components of these deployments are consistent with the ORA's findings in its evaluation of the Company's smart meter deployment.

I started the Wired Group in 2012 to focus exclusively on distribution utility performance measurement and utility customer value creation. Wired Group clients include consumer and environmental advocates, regulators, utility suppliers, industry associations, and non-profit utilities. I also teach a graduate course on renewable technologies, markets, and policy at the University of Colorado's Global Energy Management Program, and courses on distribution utility performance measurement and smart grid value creation at Michigan State University's Institute for Public Utilities (a program dedicated to educating new regulators and staff on utility industry concepts).

Finally, I am the author of Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. The book describes the challenges of translating smart grid investments into economic benefits for customers, and offers organizational, operational, customer engagement, rate design, and regulatory solutions. I received an undergraduate degree in finance and marketing from Indiana University's Kelley School of Business in 1983, and a master's degree in management from the Kellogg School at Northwestern University in 1991. A full CV is provided as Appendix A to this testimony.

[2] *Duke Energy Ohio Smart Grid Audit and Assessment*. Public Utilities Commission of Ohio Staff Report, public version, filed in 10-2326-GE-RDR on June 30, 2011. Alvarez et al.

(Stephens)

My career began in 1975, when I began work for Xcel Energy (then Public Service Company of Colorado) as an electrical engineer in distribution operations. In a series of electrical engineering and management roles of increasing responsibility, I gained experience in distribution design, planning, operations management, asset management, and the innovative use of technology to assist with these functions. In many of these roles I had to contend with the impact of distributed energy resources ("DER") on distribution assets and operations. Positions I've held over the years have included Director, Electric and Gas Operations for the City and County of Denver Colorado; Director, Asset Strategy; and Director, Innovation and Smart Grid Investments.

In 2006, my team and I won a national Edison Award for Utility Innovations. In 2007, I was asked to lead parts of Xcel Energy's SmartGridCity™ demonstration project in Boulder, Colorado, the first of its kind at the time, covering 46,000 customers. I developed the technical foundations for the project, including the development of all concepts presented to the Xcel Energy Executive Committee for project approval, and including the negotiations with technology vendors on their contributions to the project. As Director of Utility Innovations for Xcel Energy, I also worked with many software providers, including ABB, IBM, and Siemens, helping them develop their distribution automation ideas into practical software applications of value to grid owners and operators. In 2009, I established a DER integration strategy and capability road-map for Xcel Energy. The technical project components focused on Boulder, which had (and still has) the highest concentration of PV solar installations in Xcel Energy's eight-state electric service area.

I retired from Xcel Energy in 2011, and now work for the Wired Group on a part-time basis. I am a veteran of the US Air Force, where I worked on ballistic missile systems. I have a BS degree in Electrical Engineering from the University of Missouri at Rolla. A full CV is provided as Appendix B to this testimony.

Q. Have you testified before this Commission, or other state regulators, in DER-related and/or Grid Modernization cases in the past?

A. (Alvarez)

Yes. I submitted joint testimony with Mr. Stephens on behalf of TURN regarding Pacific Gas and Electric's Distributed Energy Resource Integration Capacity (DERIC) program proposal, which was part of PG&E's 2017 GRC (A.15-09-01). I have also submitted testimony to many state regulators on behalf of consumer and environmental advocates in investor-owned utilities' DER- and grid modernization-related proposals. A list is provided below, and brief descriptions are available in my CV, attached to this testimony:

Table 1: Alvarez regulatory appearances

Client (Case)	Subject of Testimony
Massachusetts OAG (15-120)	National Grid Grid Modernization Plan
Massachusetts OAG (15-121)	Unitil Grid Modernization Plan
Massachusetts OAG (15-122)	Eversource Grid Modernization Plan
Kentucky OAG (2016-00152)	Duke Energy Kentucky smart meter CPCN
Kentucky OAG (2016-00370 to 371)	Kentucky Utilities/Louisville Gas & Electric smart meter business case
Environmental Defense Fund (KCC 15-WSEE-115-RTS)	Westar rate case/ solar owner demand rates
Ohio Office of Consumer Counsel (14-2209)	Duke Energy OH interval data access
Coalition for Utility Reform (MDPSC 9361)	Exelon post-PHI acquisition distribution performance measurement & compensation

Ohio PUC Staff (10-2326-GE-RDR)	Mid-term evaluation of Duke Energy's Ohio smart grid deployment
Xcel Energy (Colorado PUC 11A-1001E)	SmartGridCity™ (Boulder, Colorado) deployment evaluation

(Stephens)

Yes. As Mr. Alvarez mentioned, I submitted joint testimony with him to the California PUC on PG&E's Distributed Energy Resource Integration Capacity (DERIC) program proposal, which was part of PG&E's 2017 GRC (A.15-09-01). I have also testified before the Colorado PUC on technical distribution grid issues unrelated to DER or grid modernization.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. (Alvarez)

My testimony will begin by putting the Company's request for dramatic increases in distribution capital into perspective, providing the Commission with context as it considers the Company's requests and TURN's recommendations. I will also describe three "recurring themes" Mr. Stephens and I observed repeatedly as we reviewed Volumes 3, 6, and 10 and the Company's responses in discovery, and that readers will encounter often as they review this testimony. One, two, or all three of these themes were observed in each of the capital requests we recommend disallowing in Volumes 3, 6, and 10. My testimony will go on to address the recommended disallowances based more on economic or regulatory arguments; disallowances which are based more on technical arguments will be addressed by Mr. Stephens. Recommended disallowances I will discuss include:

- Cerritos Channel (Port of Long Beach) Transmission Relocation capital;

- Distribution Circuit Upgrade capital.

(Stephens)

My testimony will identify the three common themes applicable to disallowances of proposals that are more technical in nature, and provide support for each observation and recommended disallowance based on information obtained in discovery, research, and personal experience. The specific technical proposals I will address, and recommend be disallowed, include:

- 4kV Substation Elimination capital (Volume 3)
- Subtransmission Relay Upgrade Program capital (Volume 6)
- Capital for Distribution Automation driven by DER (Volume 10)
- SA-3 capital (Volume 10, but also in Volume 6 as part of Substation Protection and Control Replacement capital)
- Field Area Network capital
- Wide Area Network capital
- Grid Management System capital

II. DER-RELATED CAPITAL PERSPECTIVE AND PREVIEW OF RECURRING THEMES (ALVAREZ)

Q. PLEASE PREVIEW YOUR TESTIMONY IN THIS SECTION

A. In this section I will:

1. Provide context and perspective on the Company's DER accommodation proposals, including:

a) The more cost-effectively DER growth can be accommodated, the larger the role DERs can play in achieving California's environmental goals;

b) Approval of full grid automation sets an extremely costly precedent, and merits very critical and rigorous examination by the Commission;

c) In contrast to historical grid investments, the benefits anticipated from modern grid investments are highly variable and cannot be assumed or assured.

2. Describe "recurring themes" observed repeatedly in Volumes 3, 6, and 10 which readers will encounter often in this testimony, including:

a) The Company routinely exaggerates the risks, rewards, and requirements (regulatory or operational) associated with its proposals;

b) The Company proposes capabilities whose incremental costs are dramatically out of proportion to incremental benefits;

c) The Company's proposals make no attempt to rein in DER accommodation costs, proposing high-cost approaches to deliver capabilities in instances where lower-cost approaches are available.

Q. PLEASE PROVIDE CONTEXT AND PERSPECTIVE ON THE COMPANY'S DER ACCOMMODATION PROPOSALS

A. I would like to begin by stating my, and Mr. Stephens', unequivocal agreement that the reliable accommodation of more DERs on the Company's grid is an important goal. To the extent that customer-supplied DERs can help California achieve its environmental goals more cost-effectively than other options, DERs should certainly be encouraged. Both Mr. Stephens and I also agree that expansion of certain existing grid capabilities will be required to reliably accommodate higher levels of DERs, and that such expansion will require some capital. We also appreciate that popular and political interest in accommodating more DERs is strong, as evidenced by AB327. However, we point out that the cost to reliably accommodate more DERs on the grid is inextricably linked to the overall cost-effectiveness of DERs. With this perspective in mind, it is easy to appreciate that the more cost effective the approach to accommodating DERs, the greater the role DERs can play in the achievement of California's environmental goals.

I also note that this perspective – that the lower the DER accommodation costs, the greater the role DERs will play – is shared by the solar energy industry. As noted by the Solar Energy Industries Association, "Grid upgrades must (also) be executed in a way that allows ratepayers to save money versus business-as-usual utility spending on distribution infrastructure."[3] Vote Solar states "As DERs become increasingly commonplace, we need to make sure we optimize the value of these resources and ensure that utility investments are both prudent and necessary."[4]

Q. PLEASE EXPLAIN HOW YOUR PERSPECTIVE ALIGNS WITH AB327 AND THE DISTRIBUTION RESOURCE PLAN (DRP) GUIDANCE OFFERED BY THE COMMISSION.

A. As explained by Commissioner Picker in the DRP Guidance Ruling, " . . . the DRPs must recognize a balance between promoting grid modernization technologies and minimizing the total expected investment in this system while allowing for deeper penetration of DER throughout utility grids."[5] It is this balance with which our perspective, and associated recommendations, align. However we do not agree, nor do AB327 or R.14-08-013 assume, that there is a 1 to 1 correlation between the capital dollars invested in the grid and the grid's DER capacity. Rather, our experience indicates that some capabilities provide much more DER accommodation benefit per dollar than others. Our experience also indicates that multiple approaches are generally available to secure any given capability, with concomitant variations in cost. Indeed, cost-effectiveness is the foundational objective of

[3] Gahl D, Smithwood B, and Umoff R. "New Opportunities for Solar through Grid Modernization." Paper by the Solar Energy Industries Association. April, 2017. Page 3.

[4] Smeloff D and Gallagher, S. "Tackling Southern California Edison's King-Sized Grid Modernization Investment Plan." Article on Vote Solar website. Accessed via the Internet at https://votesolar.org/usa/california/updates/investing-distributed-energy-resource-future/

[5] CPUC R.14-08-013. Assigned Commissioner's Guidance Ruling. February 5, 2015. Page 4.

grid modernization as described in the "More Than Smart" white paper, including locational benefits, optimal location, and value optimization (to include both benefit maximization as well as cost minimization).[6] In this testimony, Mr. Stephens and I will explain which capabilities deliver the highest value in DER accommodation. Furthermore, we will recommend low-capital approaches to deliver those capabilities over the high-capital approaches proposed by the Company. In essence, we are recommending the Commission consider "the 90/10 rule" when evaluating the Company's DER-related capital requests. The 90/10 rule is the notion that 90% of DER accommodation benefits can be secured with 10% of the capital proposed.

Q. PLEASE EXPLAIN WHY YOU FEEL GRID AUTOMATION MERITS VERY CRITICAL AND RIGOROUS EXAMINATION BY THE COMMISSION

A. Between volumes 3, 6, and 10, Mr. Stephens and I have identified $2.3 billion in capital requests from 2018 to 2020 related to grid operations automation, DER accommodation, and overall grid modernization. The Company makes several references in the System Planning T&D volume to its 10-year system plan, and to the idea that the DRP should be completed in the next 10 years per Commission guidance. The Company proposes distribution automation for 863 circuits, or about 20% of the Company's distribution system,[7] with this capital. Using this 20% figure as a rough guide, and assuming the

[6] DeMartini, Paul. "More Than Smart: A Framework to Make the Distribution Grid More Open, Efficient, and Resilient." Paper by the Greentech Leadership Group in co-operation with the Resnick Sustainability Institute at the California Institute of Technology. Undated. Page 5.

[7] In its response to TURN-SCE-09, Q.06.a and .06b, the Company reported 4,353 circuits of various voltages.

Company's next two GRC cycles will be used to complete the 10-year plan, a simple extrapolation indicates a total capital spend of $6.9 billion will be required to complete grid automation for just 60% of the Company's circuits, or $1,380 for each of its 5 million customers.[8] Such an investment could conceivably increase the Company's distribution gross plant balance, which stood at $20 billion as of December 31, 2015,[9] by 33% in just a decade. Investments of this magnitude must be very carefully scrutinized, taking advantage of every opportunity to avoid low-value capabilities, and to implement high-value capabilities at the lowest possible cost. For more context, as pointed out in TURN witness Mr. Hawiger's testimony, of the 37 US IOUs with more than 1 million customers, none has grown gross distribution plant by a greater amount than the Company (36.9%) from 2010 to 2015.

Furthermore, there is a significant risk that the benefits the Company anticipates from the proposed investments will not be delivered. In my experience evaluating smart grid deployments, and in Mr. Stephens's experience in distribution grid operations and the SmartGridCity™ demonstration project in Boulder, Colorado, untested, high-tech approaches rarely deliver the anticipated benefits for estimated costs. In our experience with the deployment of new, high-tech approaches, either promised capabilities are abandoned, or the capabilities require much more funding than anticipated to secure

[8] The Company's EIA Form 861 for the year ending 2015 indicates a distribution customer count of 5,019,897.

[9] The Company's FERC Form 1 for the year ending 2015 indicates a distribution gross plant balance of $20.87B.

promised benefits. In short, there is no guarantee that benefits will automatically follow from investment, or that more capital spending delivers more DER accommodation benefit.

Q. DO YOU HAVE OTHER CONTEXTUAL OBSERVATIONS TO SHARE?

A. Yes. My experience evaluating grid modernization projects post-deployment indicates that the nature of distribution investment is changing. Historically, economic development drove distribution investments. As loads from customers grew, and as populations grew, distribution investment was required to deliver ever-increasing amounts of electricity. There was no question about what was needed or the benefits to be delivered; with distribution investment, economic development could continue, and the benefits to customers and communities were clear and direct. With today's distribution investments, however, the benefits do not follow so clearly, nor so directly.

Q. PLEASE EXPLAIN.

A. Today's distribution investments can provide new capabilities. In this GRC, for example, the Company proposes to automate grid operations. Distribution automation, as the Company has defined it, appears to involve the identification and execution of grid configuration changes without human intervention. However, the degree to which modern grid investments such as distribution automation deliver actual benefits is wholly dependent on what a utility and its employees do with new capabilities once installed. With most grid modernization investments, there are interim steps between the availability of a capability and the delivery of benefits from that capability, and these steps introduce a great deal of variability in the level of benefits actually delivered. When a utility adds a new distribution circuit, the circuit immediately delivers benefits to customers. By contrast, automating a process historically carried out by humans only delivers benefits if the organization – including line employees such as grid operators – welcome the automation and enthusiastically embrace its use. Mr. Stephens – a veteran of grid operations with 30 years' experience – will confirm this in his testimony.

Q. ARE YOU SUGGESTING THAT EMPLOYEES WILL FAIL TO USE A CAPABILITY THAT MAKES THEIR JOBS EASIER?

A. No. But my experience indicates that there is often a significant difference between the capabilities employees want, need, and value, and the investments executives want to make (to grow the rate base, for example.) New capabilities can prove to be more trouble than they are worth, and a single miscue from a new capability can cause employees to revert to trusted norms. In the case of grid automation, this would mean grid operators will take the time to validate automated suggestions before allowing them to execute, which would completely elimintate the speed-related benefits of automation (as meager as they are; more on that later in this testimony). Managers can discipline an individual employee, but no manager can dismiss an entire team of experienced employees who feel they must double check recommendations before allowing, for example, a distribution switching plan they had no hand in developing to execute automatically. It will be extremely difficult for a manager to force employees to blindly trust a new capability simply to justify a utility's investment in it. Absent any urgent need or incentives to use new capabilities, there is a high likelihood they will be abandoned or go unused, and associated benefits will not be realized.

Q. YOU MENTIONED "INTERIM STEPS" REQUIRED TO SECURE BENEFITS FROM THE AVAILABILITY OF A NEW CAPABILITY. CAN YOU PROVIDE SOME EXAMPLES?

A. Many steps must happen correctly for a new capability to overcome fear, resistance to change, and legitimate operational concerns employees may have. These can include, but are not limited to, change management; testing; training; "go live" planning and preparation; business process optimization; capability innovation; changes in staffing levels, responsibiities, qualifications, and competencies; and changes in organizational and reporting structures.

To summarize, while the "degre of difficulty" associated with automating grid operations is high, the incentives to achieve associated benefits are low to non-existent. Extensive processes exist to ensure Company capital spending is recovered from ratepayers, but there are no processes in place to ensure benefits to customers follow from the investment to automate grid operations, or to ensure that employees make use of grid operations automation in a way that delivers all available benefits the Company claims it will deliver. A high degree of difficulty, combined with a complete lack of consequences for failing to deliver benefits, portends a low likelihood of success.

Q. CERTAINLY, THE COMPANY HAS EXPERIENCE WITH THESE STEPS?

A. Yes, I imagine the Company does have some experience in these matters. But no utility system conversion would be more complex, nor more impactful to mission critical operations, than the automation of grid operating decisions formerly made by humans. Furthermore, in my and Mr. Stephens' experience, no group of utility employees is as critical to reliable grid operations, nor as independent as, grid operators. And finally, few if any business process changes the Company could make would be as extensive, or as consequential, as those associated with grid operations automation. The grid operations automation the Company is proposing is in a different league from the small-scale automation the Company has already deployed.[10] Changes to the grid operations function for small-scale automation have been minimal compared to the wholesale operational changes implied by the Company's grid operations automation proposal. To conclude, I am simply asking the Commission not to assume that benefits the Company claims from grid operation automation will follow automatically from investment, which in turn calls into question the value proposition and benefit-cost ratio of investments in grid operations automation. In addition, as will be illustrated in Mr. Stephens's testimony, the benefits of grid operations automation are insufficient to justify its costs, even if everything works perfectly.

[10] SCE02V10 (Grid Modernization volume), page 35 at line 16.

Q. CAN YOU PLEASE DESCRIBE THE THREE RECURRING THEMES YOU OBSERVED IN YOUR EVALUATION OF VOLUMES 3, 6, AND 10?

A. Yes. The first of the recurring themes is that the Company often exaggerates the risks, rewards, and requirements (regulatory or operational) associated with its proposals. A partial list of the examples covered later in this testimony are highlighted below.

- A proposal to relocate a transmission line characterized by the Company as "necessary" for reliability in testimony was found instead to be the result of a franchise agreement negotiated by the Company.
- Examples of reliability issues provided by the Company to justify capital projects are most often hypothetical examples of service outages which could occur in theory. In testimony and discovery, the Company provides only three examples in which the conditions described occurred at all, or that the conditions occurred and resulted in an outage (2) or voltage violation (1).
- The Company interprets DRP guidance to "accommodate two-way flows of energy . . . enable customer choice . . . and animate opporunities for DERs to realize benefits through the provision of grid services"[11] as a requirement to automate distribution operations. In fact, no form of the word "automate" appears in AB 327 or the DRP guidance ruling.

[11] DRP Guidance at 3.

Q. PLEASE DESCRIBE THE SECOND RECURRING THEME

A. The second recurring theme is that the Company routinely proposes capabilities for which incremental costs are dramatically out of proportion to incremental benefits. The most significant example of this is grid operations automation, or the execution of grid configuration changes without grid operator intervention. While this topic will be covered more extensively in Mr. Stephens' testimony, *there is a critical distinction to be made between changing grid configurations frequently via switching to accommodate more DERs, and the automated planning and execution of these grid configuration changes*. It should be noted that the Company already has the field technology to change grid configurations frequently and conveniently via remote-controlled switches (RCS). New software applications the Company proposes in this GRC (such as the Grid Analytics Application and Grid Connectivity Model in Information Technology Volume 2),[12] or capabilities already available to it (such as the ability to access wholesale DER generation data in near-real time), will provide the capabilities required to reconfigure the grid as needed to reliably accommodate more DERs. Mr. Stephens' analysis indicates that the incremental benefits of *automating* grid operations for DERs is relatively small, particularly when compared to the exorbitant incremental costs.[13] TURN Witness Mr. Jones identifies the same finding in his testimony regarding grid operations automation for Worst-Circuit Remediation (WCR).

[12] SCE04V02, Information Technology Capitalized Software, pages 144-167.

[13] Grid Modernization volume. Table III-4, "Summary of 2016-2020 Forecast Capital Expenditures". Page 35.

Q. YOU'VE MENTIONED THE PHRASE "GRID OPERATIONS AUTOMATION" SEVERAL TIMES NOW. WHAT IS IT, AND WHAT WILL IT COST?

A. "Grid operations automation" is an umbrella term Mr. Stephens and I will use in this testimony to aggregate five proposals the Company makes to improve reliability or accommodate more DERs through automation. The five related proposals and their associated costs are listed in the table below. Grid operations automation implies a grid that reconfigures itself as needed without grid operator intervention. Both our testimony, as well as TURN witness Mr. Jones' testimony, make a distinction between grid operations automation and *grid flexibility*, or the ability to reconfigure the grid frequently and conveniently without automation. Grid flexibility can be accomplished through expanded use of more traditional technologies, such as remote controlled switches. The point Mr. Stephens and I will make in this testimony, and that Mr. Jones will make in his TURN testimony, is that it is possible – not to mention less costly and less risky – to secure virtually the same reliability and DER accommodation benefits from grid flexibility as are available from grid operations automation, but at a much lower cost.

Table 2: Summary of capital requests associated with grid operations automation

Proposal Related to Grid Operations Automation	Capital Proposed for GRC Period
Field equipment (labeled "Distribution Automation" by the Company, this estimate includes costs for 263 DER circuits at $0.6M & 600 WCR circuits at $0.5M, but excludes tie-line construction)[14]	$457.8 million
SA-3/CSP	359.8 million
Field Area Network	218.3 million
Wide Area Network	116.6 million
Grid Management System	122.4 million
Total Incremental Cost of Grid Operations Automation	$1.275 billion

Another example of incremental capital proposed by the Company in a manner out of all proportion to incremental benefits is the elimination of 4kV substations. As explained in Mr. Stephens' testimony below, the incremental cost of 4kV substation replacement exceeds the benefits by a margin of more than 3.04 to 1. The Company's proposal to automate grid operations on 74 circuits for the purposes of the distribution project capital deferral pilot is similarly flawed, as the costs exceed the benefits (assuming all distribution capital projects can be avoided or deferred, which is far from assured) by a ratio of 2 to 1. These cost-benefit ratios will be supported later in this testimony.

[14] Response to TURN-SCE-026 Q02. Tie line construction is excluded as it is needed for either grid flexibility or grid operations automation. The table is intended to segregate the incremental costs of automation.

And finally, we include in this category of oft-recurring themes the assignment of capital required to accommodate wholesale DERs to the general rate base in violation of Rule 21. In instances in which the Company proposes to accommodate wholesale DER using ratebased capital, the ratepayer benefit-cost ratio of DER-related capital can be improved dramatically by charging such capital to wholesale DER owners at cost as specified in Rule 21. There are several examples, to be covered in more detail later in this testimony:

- Of the 82.5 miles of distribution line identified for conductor or cable upgrades due to DERs, 47.05 miles (57%) are on circuits which serves wholesale DER capacity exclusively or almost exclusively. On these circuits, the ratio of wholesale DER capacity to retail DER capacity is almost 17 to 1.
- Of the 63 circuits identified for automation of the distribution function due to "Organic DER Increases" in this GRC, 9 serve wholesale DER capacity exclusively or almost exclusively. On these 9 circuits, the ratio of wholesale DER capacity to retail DER capacity is almost 32 to 1.

Q. PLEASE DESCRIBE THE THIRD RECURRING THEME

A. The third recurring theme is that the Company's proposals make no attempt to rein in DER accommodation costs, proposing high-capital approaches to secure needed capabilities in instances where lower-cost approaches are available. There are several examples which Mr. Stephens will address later in this testimony.

- All "alternatives" the Company describes in the volumes Mr. Stephens and I reviewed consist of undesirable alternatives to acquiring capabilities, rather than an examination of readily available approaches to secure high value capabilities at the lower cost. In so doing, the Company presents a false choice between spending the capital the Company proposes or failing to reliably accommodate growing amounts of DERs. This testimony demonstrates that lower-cost methods to secure high value capabilities are available in most cases, and that these lower-cost methods represent viable alternatives to the "all or nothing" characterizations which accompany the Company's DER accommodation capital proposals.

- The Company fails to take advantage of existing standards and capabilities to avoid grid modernization and DER accommodation capital spending. The Company provided just one example of a DER-related reliability challenge in testimony, and two more examples (one of which was high voltage, not an outage) in discovery. It is important to note that all three examples involve wholesale DERs, not retail DERs. It is also important to note that in all three instances, had the Company simply taken advantage of existing technical standards, wholesale DER communication capabilities, or legal provisions, the outages and voltage violations could have been avoided. Mr. Stephens will cover all three examples in the course of his testimony.

- The Company does not employ proven approaches to test, select, and deploy cost-effective solutions to DER-related problems using a risk-informed prioritization process. Mr. Stephens will describe the approach distribution utilities have used for a century to address problems as encountered in a low-cost manner. The Company does not appear to use this process to solve DER-related reliability challenges, proposing instead to deploy high-capital solutions to hypothetical problems across wide swaths of its grid, despite that fact that these solutions have not yet been shown to be the most cost-effective. Secondly, the Company does not appear to apply a risk-based prioritization process to DER-related investments, and admits specifically that its two largest grid modernization proposals -- 4kV elimination and grid operations automation -- have been subjected to no such process.[15] These processes are routinely employed by utilities around the world today; they are designed to ensure that capital to be recovered from customers is employed as cost-effectively as possible in pursuit of the highest-value capabilities.

Q. CAN YOU PLEASE SUMMARIZE THE DISALLOWANCES YOU ARE RECOMMENDING BY VOLUME?

A. Yes. Please see the table below for the disallowances we are recommending by volume.

Table 3: Summary of recommended disallowances and additions by volume.

($ in millions)	2018	GRC Period
Volume 3 Disallowances	(219.7)	(590.6)
Volume 3 Additions	4.9	14.9
Volume 3 Net Reduction	(214.8)	(575.7)
Volume 6 Disallowances	(59.8)	(182.5)
Volume 6 Additions	4.8	14.2
Volume 6 Net Reduction	(55.0)	(168.3)
Volume 10 Disallowances	(296.6)	(1,048.9)
Volume 10 Additions	38.6	115.5
Volume 10 Net Reduction	(258.0)	(933.4)
Net Reductions Volumes 3, 6, and 10	(527.8)	(1,677.4)

[15] Responses to TURN-SCE-024 Q.22.g and Q.23.a. and TURN-SCE-026 Q.53.a.

III. T&D SYSTEM PLANNING EVALUATION (VOLUME 3)

Q. PLEASE PREVIEW YOUR TESTIMONY IN THIS SECTION

A. In our Volume 3 testimony we will recommend the Commission reject capital requests totaling $214.8 million in the test year (2018) and $575.7 million for the GRC period (2018-2020). These disallowances are associated with three Volume 3 projects:

- Cerritos Channel Transmission Line Relocation ($34.0M test year; $42.0M for GRC period);
- Distribution Circuit Upgrades Due to DER ($7.2M test year; $21.5M for GRC period); and
- 4kV Substation Elimination ($173.6M test year; $512.2M for GRC period).

1. CERRITOS CHANNEL TRANSMISSION LINE RELOCATION (ALVAREZ)

Q. PLEASE EXPLAIN WHY YOU RECOMMEND THE REQUEST TO RELOCATE THE CERRITOS CHANNEL TRANSMISSION LINE BE REJECTED.

A. The Cerritos Channel Transmission Line Relocation project is an example of recurring theme #1: that the Company exaggerates the regulatory or operational requirement for an investment. In this instance, the Company places its request to relocate the Cerritos Channel Transmission Line in the Volume 3 section "Grid Reliability Projects".[16] The introduction to this section states that grid reliability projects "are necessary to provide safe and reliable service to our customers . . . ."[17] In

[16] SCE02V03 -- System Planning. Table IV-8. Page 53.

[17] Ibid, Page 52, lines 2-4.

discovery, the Company admitted that the Cerritos Channel Transmission Line Relocation project is required because it is part of a recently-executed franchise agreement with the City of Long Beach.[18] (The Cerritos Channel Transmission Line is located within the boundaries of the Port of Long Beach, owned by the City.)

I recommend the Cerritos Channel Transmission Line Relocation project be disallowed based on several grounds. First, the Company has not applied for, let alone received, a Permit To Construct from the Commission on this project, nor has it submitted an Advice Letter on this project, nor is the project part of any CAISO transmission plan.[19] Thus, I do not anticipate this project being "used and useful" in the rate case period, much less in 2018. Second, the City/Port of Long Beach requested the project, which intends to raise the transmission lines to permit the passage of larger container ships.[20] The project appears to have nothing to do with improving reliability, which suggests the project's costs should not be borne by the Company's customers ($34 million in the test year/$42 million in the GRC period) nor to California ratepayers outside the Company's service area (an additional $18.3 million over the GRC period, not considered here but of interest to the Commission). Finally, as a broader policy issue, I believe the Company should seek Commission authorization for a project of this size. In the franchise agreement with the City of Long Beach dated September 20, 2012, the Company agrees to pay for the cost of the relocation (Section 10, p. 12). Agreeing to pay $76.2 million for a project specifically to benefit the Port of Long Beach is beyond the size of a typical franchise agreement commitment. The Company has the option to use shareholder funds to renegotiate franchise agreements which are up for renewal, but the cost of

[18] Response to TURN-SCE-024, Q09.

[19] Response to TURN-SCE-070, Q01.

[20] CEQA/NEPA Scoping Meeting presentation. Slide 5. November 2, 2016.

such bargaining chips should not be recovered from ratepayers when they exceed a reasonable amount for typical projects.

In addition to rejecting proposed capital related to this project during the GRC period, I recommend the Commission disallow the recovery of $15.876 million the Company forecasts to spend on the project (CPUC-Jurisdictional; another $20.9 million outside CPUC-Jurisdictional, not considered here but of interest to the Commission) prior to the start of the test year.

2. DISTRIBUTION CIRCUIT UPGRADES DUE TO DER (ALVAREZ)

Q. PLEASE EXPLAIN WHY YOU RECOMMEND $21.5M OF THE $44.5 M IN CAPITAL REQUESTED TO UPGRADE DISTRIBUTION CIRCUITS DUE TO DER SHOULD BE REJECTED.

A. Much of the Company's request to upgrade distribution circuits due to DER is an example of recurring theme #2: that ratepayer costs are dramatically out of proportion to ratepayer benefits. In this particular instance, the incremental costs to ratepayers are excessive because the Company should have charged the costs of accommodating wholesale DERs to wholesale DER owners per Rule 21. In discovery, we found that the majority of DER capacity to be accommodated by these upgrades is wholesale DER capacity, not retail DER capacity.

The Company proposes to upgrade 82.5 miles of distribution circuits due to DER, including recabling and reconductoring.[21] Of these miles, 47.05 serve circuits with a collective ratio of wholesale DER capacity to retail DER capacity of more than 16 to 1.[22] For such circuits, including 9 with zero or near-zero retail DERs, it is impossible to conclude that the upgrades are made necessary for any type of DER capacity other than wholesale DER capacity. Such upgrades are to be charged to wholesale DER owners per Rule 21. As a result, I recommend the Commission reject recovery of the portion of the underground circuit miles serving wholesale DER primarily (49.2%, or 12.15 miles) and the portion of the overhead circuit miles serving wholesale DER primarily (60.4%, or 34.90 miles).[23] At a cost per 3-phase line mile of $1.395 million underground and $0.129 million overhead,[24] this works out to a total disallowance of $21.5 million over the GRC period. One-third of this amount is an appropriate disallowance in the test year, $7.2 million.

3. ELIMINATION OF 4kV SUBSTATIONS (STEPHENS)

Q. PLEASE EXPLAIN WHY YOU ARE RECOMMENDING THE COMPANY'S REQUEST TO ELIMINATE 4kV SUBSTATION SHOULD BE REJECTED

[21] System Planning volume, page 63, lines 5-10.

[22] Response to TURN-SCE-123 Q.21,

[23] Response to TURN-SCE-123 Q.21.

[24] Workpaper WPSCE02V08, pages 78 (overhead cost, X 3 phases) and 97 (underground cost, x 3 phases)

A. I recommend the cost of eliminating 4kV substations should be rejected for two of the recurring themes Mr. Alvarez described in the Preview. First, the Company has exaggerated the risks associated with retaining 4kV substations and associated circuits. Second, the benefit-cost ratio associated with 4kV substation elimination is dramatically negative.

I have no qualms about cutting individual 4kV circuits over to nearby 12kV and 16kV substations as needed due to overloading. It certainly makes sense that if an entire circuit is overloaded and needs to be upgraded, the Company might as well convert to 12kV or 16kV, as the cost of a cutover is likely not much more than the cost to upgrade 4kV conductors. Over time, this will gradually reduce the number of 4kV circuits. At some point, when the number of 4kV circuits gets small enough, it may make sense to convert all remaining 4kV circuits absent some immediate need, like overloading. However to proceed with elimination now, while the Company still has 1,100 circuits – almost 25% of the Company's total – on 4kV,[25] is simply too costly relative to the benefits, which I'll discuss below. If 202 circuits cost $779.8 million to eliminate,[26] then 1,100 will cost $4.25 billion to eliminate without escalation, or over $850 for each and every one of the Company's 5 million customers (even though only those customers on 4kV circuits, which we estimate to be about 12% of all customers,[27] will experience the improvements).

[25] System Planning Volume, page 76, line 2.

[26] System Planning Volume, Table IV-20, page 90, and Table IV-19, page 76.

[27] In response to TURN-SCE-024 Q.16.a, the Company reports 111,000 customers on the 202 4kV circuits identified for elimination. Extrapolated to the 1,100 4kV circuits, we estimate 4kV customers at 604,445.

To place this amount into perspective, I calculated the SAIDI difference between 4kV circuits and other circuits from information obtained in discovery. I found that SAIDI was about 25 minutes higher per year on 4kV circuits than on other circuits on average. In percentage terms, some might consider this a significant difference. But I doubt very few customers would choose to pay $850 for 25 minutes' more service a year, particularly if only 12% of customers (those served by 4kV circuits today) experience the 25-minute improvement from the investment. I encourage the Commission to take these factors into account when considering the Company's capital request to continue the 4kV elimination program.

Q. PLEASE SUPPORT YOUR CLAIM THAT THE COMPANY HAS EXAGGERATED THE RISKS ASSOCIATED WITH RETAINING 4kV SUBSTATIONS AND CIRCUITS.

A. The Company describes multiple drivers for eliminating 4kV substations and circuits. Other than reliability and energy losses, which I'll discuss below, none of the drivers offers significant economic benefit. Nor can the Company provide any regulatory justification for eliminating 4kV substations and circuits based on the non-economic drivers.

Q. CAN YOU PROVIDE ANY EXAMPLES?

A. Yes. Under the "old and obsolete equipment" driver, the Company cites that 4kV parts and equipment are difficult and expensive to procure, that old 4kV substations fail to meet the standards for new substation construction, that much 4kV equipment is old, and that some equipment contains PCBs. In discovery, the Company admitted that none of these issues, in and of themselves, constitute a requirement to eliminate 4kV substations and circuits.[28] As other examples, the Company states that 20% of its 4kV circuits are islanded, with no opportunity to transfer loads in order to perform maintenance.[29] (The implication of this is that customers' service must be interrupted to perform such maintenance.) In discovery, I found that only 16.5 % of 4kV circuits are islanded,[30] that the Company uses temporary transformers, upgrades, and connections to avoid planned outages during maintenance on islanded circuits,[31] and that the Company could not document a single customer outage due to planned maintenance on a 4kV substation or circuit.[32]

I also cite the Company's claims that 4kV circuits will limit DER growth as an exaggeration example. In discovery, the Company admitted it has never had to limit DER deployment on a 4kV circuit to date, and cannot document a single outage related to DER on a 4kV circuit.[33] Yet another exaggeration, in my opinion, is the Company's claim that many utilities are eliminating 4kV circuits.[34] While many utilities are indeed eliminating 4kV circuits, to my knowledge these are due to approaching overload conditions. That is,

[28] Responses to TURN-SCE-024 Q.17; TURN-SCE-063 Q.15; TURN-SCE-063 Q.36.a; and TURN-SCE-063 Q36b.

[29] System Planning Volume, page 79, lines 19-23.

[30] Response to TURN-SCE-063 Q.19.a

[31] Response to TURN-SCE-063 Q.21.b

[32] Ibid

[33] Response to TURN-SCE-063 Q.41.

[34] System Planning volume, page 77, lines 15-16.

if a 4kV line must be replaced due to load growth anyway, the minor incremental cost of converting to 12kV at that point makes such cutovers (from 4kV to 12kV) worthwhile, as the Company points out in testimony and with which I agree. However, I know of no utility which is presumptively replacing hundreds of circuits for reasons other than overloads as the Company is proposing. This is likely because, in my experience, cost-benefit analyses of such efforts are always unfavorable. The Company could not produce a favorable cost-benefit analysis for presumptive replacement,[35] nor could the Company produce a favorable cost-benefit analysis calculated by any other utility.[36]

As a final example, I'd like to cite voltage issues. On this, the Company does not exaggerate; voltage issues are worse on 4kV circuits, with 5 customer complaints per 1,000 customers per year compared to 2.5 customer complaints per 1,000 customers per year on 12kV and 16kV circuits.[37] However, using customer count data provided in discovery on the 202 4kV circuits identified for elimination,[38] the 2.5 difference in voltage complaints equates to an extra 278 voltage complaints annually. I cannot justify, even in part, a $779 million capital request to avoid 278 voltage complaints a year.

[35] Responses to TURN-SCE-024 Q.32.b, 33.b, 34.b, 35.b, 36.b, 37.b, 38.b, 39.b, 40.b and 44.c.

[36] Response to TURN-SCE-024 Q.31.b.

[37] Response to TURN-SCE-024 Q.16c and Q.16.d.

[38] Average customer count on 4kV circuits identified for elimination in this GRC period is 549.6 per the response to TURN-SCE-024 Q.16.a

Q. PLEASE SUPPORT YOUR CLAIM THAT THE BENEFIT-COST RATIO ASSOCIATED WITH 4kV ELIMINATION IS DRAMATICALLY NEGATIVE.

A. As a former manager of grid operations, capacity planning, and asset management functions, I can appreciate the interest in eliminating 4kV substations and their circuits. However, in years of attempts to develop an economic justification for 4kV substation and circuit elimination, I have never been able to do so. My evaluation of the Company's 4kV elimination program confirms that it is difficult, if not impossible, for the benefits of 4kV elimination to exceed the costs for customers. I note that ORA witness Mr. Roberts recommends 4kV elimination funding based largely on the fact that the ORA "did not oppose the Company's request" in the 2015 GRC. I understand that neither ORA nor TURN completed a cost-benefit analysis of 4kV elimination in prior rate cases. I was able to complete such a cost-benefit analysis, however, and describe the method and outcome here.

As I see it there are three sources of economic value from 4kV elimination: reductions in line energy losses (the higher the voltage, the lower the losses); reductions in customer minutes interrupted; and reductions in momentary interruptions. From data obtained in discovery, I have calculated the present value of switching 4kV circuits to higher voltages for energy losses (using $0.0565/kWh);[39] reductions in customer minutes interrupted (using $2.32 per minute interrupted);[40] and momentary interruptions (using $91.05 each)[41]

[39] $4.266 B fuel cost 2015, Appendix A, A.16-05-001; 75,438.2 GWh sales to "bundled" customers, EIA-861, 2015.

[40] Workpaper WPSCE02V10, page 124.

[41] Ibid, page 125.

on a per substation basis (including all attached 4kV circuits). I then compared these benefits per substation to the cost per 4kV substation eliminated to produce the table below. Present values were calculated using a 25-year circuit life and a 7.9% discount rate.[42]

Table 4: Present Value of Benefits and Costs of 4kV Substation Elimination

Item	Present Value of (Cost) or Benefit per Substation
Average Cost to Eliminate a Substation – total	($14.9 million)
Average Benefit from Energy Losses	1.8 million
Average Benefit from Customer Minutes Interrupted	1.7 million
Average Benefit from Momentary Interruptions	1.4 million
Total Average Benefits	4.9 million
Ratio of Costs to Benefits	3.04 to 1

In other words, customers pay at least $3.04 for every $1 in benefit received from 4kV elimination. I say "at least", because the $14.9 million cost per 4kV substation eliminated does not include the cost of interest, profits, or corporate income taxes on profits, which customers will have to pay when the $14.9 million capital cost is recovered in rates. Moreover, not only does substation elimination fail the cost-benefit test in total, none of the 51 substations I analyzed passed a cost-benefit test on an individual basis either.

However, several circuits came very close to a break-even point, including the Braemer circuit out of the Playa substation; the Dempsey circuit out of the Oxnard substation; the Clemont circuit out of the Naomi substation; and the Adriatic circuit out of the Larder

[42] Workpaper WPSCE09V02, Chapter IV, BkA. Page 182.

substation. As I used some approximations of circuit lengths and conductor sizes in my analysis, a more detailed analysis could possibly deliver a favorable cost-benefit analysis for these specific circuits. I also compared the list of circuits located in disadvantaged communities to the list of circuits the Company proposes to eliminate, noting that only 12 were on both lists. As a result of these two observations, I recommend $14.9 million be added back to the Company's capital request, enabling the elimination of one additional substation or to fund cutovers for individual circuits. With more detailed analysis and in consideration of improvements to circuits serving disadvantaged customers, the Company can best determine how to spend these funds to optimize the benefits.

Q. DO YOU HAVE ANY OTHER RESERVATIONS ABOUT THE COMPANY'S PROPOSAL TO ELIMINATE 4kV SUBTATIONS AND CIRCUITS?

A. Yes. As described in the Preview, a risk-informed prioritization process can help a utility put capital to its highest and best use. Risk-informed prioritization processes are designed to help utilities deploy capital first to the biggest reliability risks it faces, and avoid deploying capital where such deployment would deliver less reliability benefit. Such processes help utilities maximize customer "bang for the buck".

In discovery, the Company confirmed the 4kV elimination program has not been subjected to a risk-informed prioritization process.[43] In my experience, and as confirmed by my cost-benefit analysis of the Company's 4kV elimination program, I do not believe such a

[43] Response to TURN-SCE-024 Q.22.g and Q.23.a.

program would have ever been selected for implementation had it been subjected to a risk-informed prioritization process. There are undoubtedly much better ways for the Company to spend capital to be recovered from customers than 4kV substation and circuit elimination.

I recommend the Commission approve capital requested for "cutovers" of overloaded 4kV circuits, and that such funding continue in the future. But I recommend that the 4kV elimination program be halted as soon as possible, and all future cost recovery denied.

Q. COULD YOU PLEASE SUMMARIZE THE FINANCIAL IMPACT OF YOUR RECOMMENDATIONS TO THE COMPANY'S CAPITAL REQUST FOR 4kV ELIMINATION?

A. Yes. Please see the summary table below.

Table 5: Summary of recommended adjustments to the Company's 4kV Elimination capital request.

($ in millions)	**Test Year**	**GRC Period**
Reject the Company's 4kV Elimination proposal[44]	($178.6)	($527.1)
Add capital for additional cutovers/1 substation elimination	4.9	14.9
Net reduction to the Company's 4kV Elimination Request:	($173.7)	($512.2)

[44] System Planning volume. Table IV-19. Page 76.

IV. T&D SUBSTATION CONSTRUCTION AND MAINTENANCE EVALUATION (VOLUME 6 -- STEPHENS)

Q. PLEASE PREVIEW YOUR TESTIMONY IN THIS SECTION.

A. In my Volume 6 testimony I will recommend the Commission reject capital requests totaling $55.0 million in the test year (2018) and $168.3 million for the GRC period (2018-2020). These disallowances are associated with two Volume 6 projects:

- Subtransmission Relay Upgrade Program -- $41.6 million test year and $128.7 million GRC period; and
- Substation Protection & Control Replacements/SAS Replacement/SA-3/CSP -- $13.4 million test year and $39.6 million GRC period.

The SAS Replacement/SA-3/CSP technology is the same as that discussed in Volume 10 Grid Modernization. I will discuss the Company's SA-3/CSP proposal here and not repeat it in my Volume 10 testimony. In the testimony below I will recommend the SA-3 design be rejected but the CSP proposal be approved. The CSP will require some capital to implement (about $218,300 per substation, see below), and I recommend this smaller capital amount be approved in lieu of the capital requested by the Company ($827,000 per substation). The SA-3/CSP disallowances above reflect the net difference between my recommendation and the Company's capital request.

1. SUBTRANSMISSION RELAY UPGRADE PROPOSAL

Q. PLEASE EXPLAIN WHY YOU ARE RECOMMENDING THE SUBTRANSMISSION RELAY UPRGRADE PROGRAM BE REJECTED.

A. The Substransmission Relay Upgrade program is an example of recurring theme #1: that the Company exaggerates the requirements (in this case operational) and risks associated with its Subtransmission Relay Upgrade proposal. The Company claims that "load encroachment", or reverse power flow, will confuse the relays (circuit breakers), causing them to remain closed when they should open (interrupt power) under a fault condition, leading to equipment damage and service outages.[45] Though this "problem" is cited commonly by investor-owned utilities interested in growing their ratebases through relay replacement, and by relay manufacturers interested in increasing revenues, there is absolutely no evidence that reverse power flows from PV solar inverters have caused relays to remain closed when they should open. I support this statement in several ways.

First, I know of no instances in which reverse power flows from PV solar inverters have caused relays to remain closed when they should open. Reverse power flow from synchronous generators (like a gas-fired turbine) can cause this problem, which is why the "problem" remains one for which PV solar inverters are deemed guilty by association (erroneously) in industry circles. Since the Company knows the size and location of its synchronous generators, it can apply an appropriate solution in cases where reverse power

[45] Substation Construction and Maintenance Volume, page 32, line 13 to page 33, line 6.

flow from synchronous generators may be an issue. But to replace relays system wide, when the vast majority of distributed generation is PV solar, spends capital in search of a hypothetical problem.

Second, the Company admitted in discovery that it has not experienced a single instance in which a load encroachment condition by a PV solar inverter caused a relay to remain closed during an outage condition, nor could it cite examples of any equipment damage or any outages.[46] The Company also admitted in discovery that it has not tested existing relays under conditions of reverse power flow.[47] While the Company's internal analysis hypothesizes that the problem described could occur in theory, the Company provides no independent studies which confirm that relays are prone to remaining closed in fault conditions due to reverse power flow from PV solar inverters. It is also worthwhile to note that IEEE standard 1547 requires PV solar inverters to disconnect from the grid in the event of a fault,[48] as does Rule 21_1.

Third, there are multiple studies which confirm that PV solar inverters contribute insignificant current in fault conditions. These studies indicate that individual PV solar inverters require no more than 1 cycle (1/60th of a second) to disconnect in fault conditions.[49] Even in a worst-case scenario, where multiple PV solar inverters are grouped

[46] Response to TURN-SCE-025 Q.15.d.

[47] Response to TURN-SCE-061 Q.09

[48] IEEE 1547 Subsection 4.2.1. "Area EPS (electric power system) Faults". 2003. Page 7.

[49] Keller J. and Kroposki B. "Understanding Fault Characteristics of Inverter-Based DER". Technical Report TP-550-46698. National Renewable Energy Laboratories. January, 2010. Pages 16-19.

in close proximity, one study found it could take up to 10 cycles (1/6th of a second) for all PV solar inverters to disconnect in fault conditions.[50] Since these timeframes are well within the trip timeframes at which most relays are typically set, or at which almost all relays could be set, it is safe to ignore this extremely temporary situation, assuming PV solar inverters are IEEE 1547-compliant. (This is just one illustration of why, as noted in the Preview to this testimony, compliance with IEEE 1547 should be required as part of the Company's interconnection standard.)

2. VOLUME 6 COMPONENTS OF THE SA-3 PROPOSAL

Q. PLEASE EXPLAIN WHY YOU ARE RECOMMENDING THE SAS REPLACEMENT/SA-3/CSP PROPOSALS IN VOLUMES 6 BE REJECTED.

A. The Company is proposing to replace the Substation Automation Systems (SAS, the devices that remotely control substation equipment) at 65 substations with the same technology the Company describes in Volume 10 (Grid Modernization). The Company calls the proposed technology "SA-3/CSP". The only difference between Volume 10 and Volume 6 applications is that in Volume 10 the justification is the proliferation of DERs, while in Volume 6 the justification is to upgrade subtransmission substations (those serving higher-voltage 66kV and 115kV circuits) to the same SA-3 standard the Company claims

[50] Katiraei, F. "Investigation of Solar PV Inverters Current Contributions during Faults on Distribution and Transmission Systems' Interruption Capacity". Quanta Technology.

is required for distribution substations serving circuits with large amounts of DERs. In Volume 6, the Company provides no rationale whatsoever for replacing the existing SAS at 65 subtransmission substations, other than "SCE finalized the design to replace the . . . first generation integrated systems (relays and control computers), and programmable logic controllers (PLC)."[51] In other words, the Company proposes to replace its SAS at subtransmission substations in Volume 6 for no other reason that the fact that the Company is changing its substation control system standard to SA-3/CSP.

In my review of the SA-3/CSP standard, and with the assistance of TURN witness Mr. Kovar, I believe the CSP portion of the SA-3/CSP standard offers valuable cybersecurity protections, as well as low-latency access to substation equipment via the existing WAN (rather than the somewhat slower NetComm communications system the Company uses to access these devices today). However, I believe the SA-3 standard is completely unnecessary.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE SA-3 PORTION OF THE COMPANY'S SA-3/CSP STANDARD IS UNNECESSARY.

A. There are three reasons, which I will address in turn:

- The need to change substation breaker settings to accommodate grid reconfigurations is extremely rare.

[51] SCE02V06 Substation Construction and Maintenance Volume. Page 31, line 11.

- As indicated in my substation relay upgrade testimony above, there is no risk of PV solar systems contributing to fault current, and therefore no need to adjust breaker settings due to the presence of PV solar.
- Even if it were necessary to adjust substation breaker settings, or other equipment settings, frequently and dynamically, there are much less expensive ways to do so.

All of the Company's justifications are actually presented in its Volume 10 (Grid Modernization) testimony, though I address them here as the proposed technology is the same.

First, in Volume 10 the Company cites changes in circuit impedance, resulting from grid reconfigurations, as justification for "frequent and dynamic" adjustments to substation circuit breakers.[52] In my experience, the need to adjust circuit breaker settings for grid reconfigurations or resulting impedance changes is exceedingly rare. In discovery I asked for the incidence of such adjustments out of the 20,000 reconfigurations the Company executed in 2015, but did not receive a response in time to include it in this testimony. However, I would be surprised to find any incidences at all, or perhaps no more than 5-10.

Second, as indicated in my substation relay upgrade testimony above, there is no risk of PV solar systems contributing to fault current, and therefore no need to adjust breaker settings due to the presence of PV solar. As a result I do not believe the Company can cite PV solar systems as a rationale for frequent and dynamic circuit breaker setting adjustments.

[52] Grid Modernization volume, page 62, line 10 through page 64, line 7.

Finally, though I do not agree that there is any need to adjust substation circuit breaker settings remotely and dynamically today, if that need arises in the future, or is needed for other substation equipment, there are much less expensive ways to implement the capability than the Company proposes. The Company states in Volume 10 that it must implement the SA-3 approach to ensure it can access and control substation equipment settings via TCP/IP (Internet Protocol), and that the SA-3 approach is needed for compliance with the IEC 61850 standard for interoperability. I am aware that advanced PLCs and RTUs (the controllers the Company uses to execute instructions to substation equipment today) are available which are compliant with the IEC 61850 interoperability standard, and the Company confirmed this in discovery.[53] I am also aware that advanced PLCs and RTUs offering TCP/IP connectivity are available, and the Company confirmed this in discovery.[54] In my experience, these devices can be installed at a cost of $10,000 to $15,000 each. Assuming one or even two substation devices per circuit must be controlled remotely and dynamically, which as I describe above is doubtful, the cost per substation would be $75,000 to $150,000 (assuming 5 circuits per substation, the Company's average).[55] This cost is 3% to 6% of the Company's SA-3 proposal ($2.45 million per substation.)[56] Then there is the issue of a building to house substation controllers, which the Company estimates at $500,000 per substation. In my experience, air-conditioned trailers are available for less than 10% of this amount and can very

[53] Response to TURN-SCE-026 Q.38

[54] Response to TURN-SCE-065 Q.24.b

[55] Response to TURN-SCE-009 Q.06.a-b

[56] Response to TURN-SCE-026 Q.35

adequately serve the purpose of housing controllers, other substation computing equipment, and back-up batteries.

To summarize, I recommend the SA-3 component of the Company's SA-3/CSP proposal be rejected. To the extent advanced PLCs and RTUs are needed for more advanced control capabilities in the future, the Company can install those on an as-needed basis at a low cost. In addition to the dramatically lower cost, another advantage is that the simplicity of the approach helps reduce the need for more communications bandwidth in the field. The greater bandwidth requirements of the SA-3 solution is one of the justifications the Company cites in its testimony in support of its wide area network (WAN) capital request.[57] I discuss capital requests related to WAN in my Volume 10 Grid Modernization testimony later.

Q. HOW MUCH WILL YOUR PROPOSED APPROACH COST TO IMPLEMENT?

A. In discovery the Company reported that the CSP components of its SA-3/CSP proposal could be implemented at a cost of $193,326 per substation.[58] I recommend rejecting the Company's SA-3 Volume 6 proposal cost of $827,000 per substation[59] in its entirety. In its place, I recommend adding back the CSP capital, plus an allowance of $25,000 per substation for equipment housing. (The allowance is not $50,000 per substation, as I am assuming half of the substations currently have a building in which CSP equipment can be

[57] Grid Modernization volume, page 84, line 10.

[58] Response to TURN-SCE-026 Q.35.

[59] Substation Construction and Maintenance volume, Table I-13, page 32.

installed). The net reduction to the capital request is $608,700 per substation (827,000 disallowance less $193,300 allowance for CSP equipment and $25,000 allowance to house the CSP equipment.) For 22 substations in the test year, the net disallowance is $13.4 million; for 65 substations in the GRC period, the net disallowance is 39.6 million. A table summarizing the capital impact of my recommendations is provided below.

Table 6: ***Summary of recommended adjustments to the Company's Volume 6 SA-3/CSP capital request***

($ in millions)	**2018**	**GRC Preiod**
Reject the Company’s SA-3/CSP proposal	($18.2)	($53.8)
Add back capital for CSP ($193,300 per substation) and equipment housing allowance ($25,000 per substation)	4.8	14.2
Net reduction to the Company’s SA-3/CSP capital request:	(13.4)	(39.6)

V. T&D GRID MODERNIZATION EVALUATION (VOLUME 10, STEPHENS)

1. SECTION PREVIEW & PERSPECTIVE ON GRID OPERATIONS AUTOMATION

Q. PLEASE PREVIEW YOUR TESTIMONY IN THIS SECTION.

A. In my Volume 10 testimony I will recommend the Commission reject capital requests totaling $258.0 million in the test year (2018) and $933.4 million for the GRC period (2018-2020). These disallowances are associated with four Volume 10 proposals related to grid operations automation, as well as the Volume 10 portion of the SA-3 proposal just discussed. The four Volume 10 proposals related to distribution automation include:

- Distribution Automation (DA) due to DER ($85.1M test year and $263.3M GRC period);
- Field Area Network (FAN; $14.2 M test year and $197.3 M GRC period);
- Wide Area Network (WAN; $39.0 M test year and $116.6 M GRC period); and
- Grid Management System (GMS; $19.8 M test year and $62.4 M GRC period).

My testimony recognizes that increased grid flexibility will be required to reliably accommodate more DERs, and I suggest replacing these disallowances with smaller amounts of capital to implement grid flexibility on a more limited basis, though notably without grid operations automation (to be further discussed below). This replacement capital includes:

- $33.5 M for the deployment of increased distribution grid switching capabilities, including remote control switches (RCS) and associated tie lines for 54 of the 63 circuits the Company identifies for ”Organic DER Growth”, spread out over the GRC period;
- $1.9 million for expansion of/upgrades to the NetComm communications system, spread out over the GRC period;
- $60 million for the deployment of an Advanced Distribution Management System and DER Management System (ADMS and DERMS), spread out over the GRC period. ADMS and DERMS offer all of the capabilities of the Grid Management System proposed by the Company except for grid operations automation.

These additions are included as offsets in the recommended disallowance amounts listed above.

My Volume 10 testimony will also recommend the rejection of the SA-3 proposal in favor of the SAS-2 upgrades I described in my Volume 6 testimony, for the same reasons. As described in Volume 6, this recommendation involves disallowing SA-3 upgrade capital and replacing it with smaller amounts of capital for the advanced SAS-2 approach I propose. This recommendation rejects $106.7M in capital for the test year and $313.9M in capital for the GRC period, but replaces it with $6.8M in capital for the test year and $20.1M in capital for the GRC period, for net reductions of $99.9M and $293.8M respectively.

Q. PLEASE OUTLINE YOUR TESTIMONY IN THIS SECTION.

A. I will begin with some "big picture" perspectives, including the identification of recurring themes as described in the Preview; an overall perspective on grid operations automation, with a focus on grid state estimation and reconfiguration in a high-DER environment; and the root causes of DER reliability challenges, including power flow and masked load, which are completely consistent with the Company's testimony and examples. I will identify several actions the Company could be taking, but does not appear to be taking, to avoid DER-related challenges without large capital investments. I will then address each component of the Company's automation proposals -- DA, FAN, WAN, and GMS – discussing my observations on each, and offering low-cost alternatives to increase grid flexibility and accommodate more DERs without the enormous cost of grid operations automation. I will also briefly revisit the observations and alternatives for the Company's SA-3 proposal as described in my Volume 6 testimony previously. I will take an opportunity to describe overall concerns with the Company's grid modernization planning approach. Finally, I will summarize my Volume 10 testimony, making a case that grid operations automation due to DERs is not worth the enormous investment.

Q. PLEASE EXPLAIN WHY YOU ARE RECOMMENDING THE COMMISSION REJECT THE COMPANY'S GRID OPERATIONS AUTOMATION PROPOSAL (DUE TO DER) AND ITS COMPONENTS (DA, FAN, WAN, AND GMS).

A. All of the recurring themes Mr. Alvarez presented in the Preview to this testimony are in evidence in the Company's proposal to automate grid operations. First, the Company exaggerates the risks, rewards, and regulatory requirement to automate grid operations. Second, the incremental costs of grid operations automation outweigh the incremental benefits of automation by an extremely wide margin. As part of this cost-benefit mismatch, I note that while large wholesale DERs contribute the greatest proportion of DER-related reliability challenges on the circuits to which they connect, the Company proposes to address them through ratebased investments in violation of Rule 21 (which requires that such costs be charged to wholesale DER owners). Third, the Company proposes high capital approaches (grid operations automation) to satisfy its need for more frequent grid configuration when much less expensive approaches to grid flexibility are available.

Q. WHAT IS YOUR OVERALL VIEW OF THE COMPANY'S GRID OPERATIONS AUTOMATION PROPOSAL?

A. Throughout its Volume 10 testimony, and in the multiple examples provided in Appendix A, the Company describes a process most utilities call "grid state estimation". Grid operators who wish to change grid configurations today, either for planned maintenance work or in response to an unexpected outage, manually estimate loads and power flows for various sections of circuits involved in a potential reconfiguration, as illustrated by multiple examples the Company Provides in Attachment A to the Grid Modernization volume. To accurately complete a grid state estimation effort, and then go on to execute the appropriate new grid configuration, several capabilities are needed:

1. A way to generate (or estimate) information on the current grid state, including information on both DER and loads;
2. A way to communicate information on the current grid state back to grid operators (or, as the Company proposes, back to a grid management system, or GMS);

3. A way for grid operators to analyze information on the current grid state, and to estimate the impact of any configuration changes; and
4. A way to execute the changes through switching.

Grid state estimation and reconfiguration are among the grid operator's primary responsibilities. The Company states it reconfigures its grid thousands of times annually, and the state of the grid is estimated prior to each reconfiguration. The Company is claiming that the proliferation of DERs is simply making the process, and in particular step 3, too complicated for grid operators to manage. I agree the grid operators could use some assistance for step 3, and this assistance is available in the distribution applications the Company proposes in Information Technology Volume 2 (for example, the Grid Connectivity Model, or GCM, and the Grid Analytics Application, or GAA). The Company's proposals for DA, FAN, WAN, and GMS go a step further, and suggest that grid state estimation, reconfiguration, and execution processes should be executed automatically, without human intervention, judgement, or delay. While this is a great vision for what distribution utilities should work towards over time, I believe it to be extremely premature and even unrealistic relative to current distribution utility planning and operating norms, including those employed by the Company. The Company's grid operations automation proposal constitutes a "sprint" in conflict with the more pragmatic Walk-Jog-Run® approach now recommended by the authors of the *More Than Smart* whitepaper on which much of the DRP Guidance is predicated.[60] My experience tells me

[60] Shumavon A, De Martini P, and Wang L. Data and the Electricity Grid: A Roadmap for Using System Data to Build a Plug & Play Grid. White Paper. More Than Smart. Undated. Page 4.

the walk-jog-run approach is the most appropriate way to progress to an automated grid operations vision.

Q. WHAT WOULD YOU PROPOSE IN PLACE OF THE COMPANY'S AUTOMATION PROPOSAL?

A. I would propose a more measured evolution of the Company's capabilities, including lower-cost, graduated advances in each of the four components of the grid state estimation and reconfiguration process. These advances will improve grid flexibility and enable the Company to address the root causes of DER reliability challenges at a dramatically lower cost with much greater chances of success. I would also like to point out that none of my recommendations is inconsistent with pursuing grid operations automation over time.

Q. DO YOU BELIEVE THE COMPANY'S GRID OPERATIONS AUTOMATION PROPOSAL IS LIKELY TO DELIVER ANTICIPATED BENEFITS?

A. I think the odds are stacked against it. My experiences with attempts to automate grid operations are consistent with the observations Mr. Alvarez made in the Preview. I have observed:

- The cost to make automation work always exceeds anticipated/budgeted costs;
- Grid operator resistance is significant;
- Many accommodations are made simply to get automation to work at all, or to contain over-budget spending;

- These accommodations negate most if not all of the small incremental benefits anticipated by grid operations automation proponents.

Q. PLEASE PRESENT YOUR PERSPECTIVE ON THE ROOT CAUSES OF RELIABILITY CHALLENGES DER PRESENTS.

A. I would not characterize the perspective I am about to describe as mine; in fact, I share the Company's perspective on what the DER-related challenges are. In testimony the Company provides multiple examples of how large amounts of DERs on the grid can present reliability challenges. All of these examples can be traced to one of two root causes:

- Changes in power flow due to DER; and
- Electric loads which are "masked" due to DER (hidden due to DER generation).

Changes in power flow caused by DERs do cause unpredictable circuit loading during switching operations, primarily resulting from masked loads. It is also true that loads which are "masked" by generation on the distribution system present challenges to grid operators as described in the examples provided by SCE.

However, the Company concedes that these challenges can be alleviated through added transparency to the output of specific DERs.[61] Added transparency about DER output can be accomplished by providing grid operators with direct access to the output data of

[61] Response to TURN-SCE-065 Q.11.a.

larger DERs in near-real time as described in the CAISO interconnection standard, Rule 21 Section J.5, or through access to the DER provider network. This transparency to actual near-real time output of each connected DER system can help resolve all of the masked load problems described by the Company in its grid modernization volume and appendices.

The information from these near-real time DER outputs, used in combination with the loading estimates as described in the examples can be used to calculate the power flows on the system and resolve the issues described in these examples, including the use of DER to help relieve overloading conditions, without automation. I will discuss this in detail shortly.

Q. DO YOU BELIEVE THE COMPANY'S GRID OPERATIONS AUTOMATION PROPOSAL WILL ADDRESS THESE ROOT CAUSES?

A. Yes, but it does so in a very capital intensive manner. Moreover, my experience indicates grid operations automation will cost more than expected and may still not deliver anticipated capabilities. I believe a lower-risk approach is available at a dramatically lower cost. This approach will effectively manage high levels of DERs using more traditional methods and technologies to facilitate grid reconfigurations without automation. If I were in charge of the Company's grid operations, I'd concentrate on improving visibility into power flow and masked load, rather than pursuing grid operations automation.

Q. HOW WOULD YOU GO ABOUT IMPROVING VISIBILITY INTO POWER FLOW AND MASKED LOADS?

A. Improving power flow visibility is a matter of enforcing, and making good use of, existing and developing standards regarding DER generation data access. For example, I was surprised to find that the Company's current wholesale interconnection agreements fail to mandate DER communications capabilities and data access in accordance with IEEE standards 1547 and 2030.5.[62] I also see evidence that the Company fails to use the existing wholesale DER data access already provided for by Rule 21, Section J.5., which indicates only that wholesale DER output metering "may" be required by the Company at the DER owner's expense.[63] I discuss examples below.

The Company's characterization of the only example of a DER-related outage it cited in testimony provides still more evidence supporting the solar industry's assessment that California IOU's prefer "build more to profit more" over approaches designed to avoid gold plating,[64] such as improved visibility into power flow through DER data access. In testimony, the Company implies that the lack of a distribution automation capability, and a Grid Management System in particular, contributed to an outage resulting from a 2MW Wholesale DER owner's failure to curtail output when requested.[65] In discovery, the Company admitted that "real time information about the output of each generator coupled

[62] Standard Generator Interconnection Agreement provided in response to TURN-SCE-065 Q.01.a.

[63] Rule 21.

[64] Solar City white paper, page 2.

[65] Grid Modernization volume, page 47, lines 12-22.

with advanced power flow and (grid) state estimation would be needed to avoid this potential outage".[66] The Company also admitted in discovery that it can require wholesale DER providers to provide communications (one way, from the DER to SCE) for DERs of 1MW or greater per Rule 21, Section J.5.[67] Yet it appears in this case that the Company failed to require DER data access, or failed to maintain DER data access, or failed to use access to DER data access to verify curtailment. In any event, the Company's failure to require, maintain, or use existing DER data access capabilities, not the absence of automation, appears to be the cause of the only DER-related outage the Company cites in its testimony.

Before leaving this sole example of a DER-related outage the Company cited in testimony in support of its $1.275 billion automation proposal, I also wish to point out that it is yet another example of the Company's exaggerations regarding DER-related reliability risks. In this outage, only 872 customers were without service for 10 minutes.[68] It is also worthwhile to note that on one of the two circuits in this example, the ratio of wholesale DER capacity to retail DER capacity was 55 to 1; the ratio of wholesale to retail DER capacity was 7.8 to 1 on the other circuit.[69]

[66] Response to TURN-SCE-026 Q.03.c.

[67] Response to TURN-SCE-107 Q.16.a-c.

[68] Responses to TURN-SCE-026 Q.03.a and Q.03.b.

[69] Response to TURN-SCE-127 Q.01.f and Q.01.g

Q. ARE THERE OTHER EXAMPLES OF OUTAGES CAUSED BY THE COMPANY'S FAILURE TO ACCESS WHOLESALE DER GENERATION DATA?

A. Yes. The Company provided a second example of an outage related to wholesale DER in discovery.[70] This example demonstrates yet again the critical importance of visibility to DER generation data. In a follow-up inquiry, the Company stated "If SCE had the ability to correctly estimate generation and load at a circuit segment level, SCE would have the ability to identify this masked load condition."[71] Given that the Company has the right to demand telemetry for wholesale DERs in excess of 1MW per Rule 21_1 J.5, and given that the size of the DER in this example was 20MW, I do not understand why the telemetry was not demanded by the Company for routine use by grid operators.

Despite the highly critical nature of securing DER generation data in near-real time for the purposes of addressing the root cause DER reliability challenges of power flow and masked load, a discussion of it is conspicuously absent from the Company's grid modernization volume. In fact, no means for transmitting DER data in near-real time is described anywhere in the Company's testimony. The phrase "DER Provider Network" appears once in a diagram[72] but is not explained or described. This lends additional credence to the

[70] Response to SEIA-VoteSolar-SCE-005 Q.05

[71] Response to TURN-SCE-127 Q.03.a

[72] Grid Modernization volume, Figure I-3, page 15,

above-noted solar industry claim that California IOUs would rather fix problems with capital than avoid them with readily available capabilities.

The Company's intransigence on this critical issue was also made clear in discovery. When asked what might preclude the Company from using the Smart Inverter Working Group's Phase II recommendations to improve power flow visibility, or to describe any plans the Company had to use the Phase II recommendations to improve power flow visibility, the Company responded: "Phase II recommendations provide the capabilities to communicate, but do not require communications to be installed to make use of these capabilities."[73] At both the wholesale and the retail level, it appears the Company is not aggressively pursuing the DER data access capabilities it could be pursuing, nor does it appear that the Company has integrated such data access into its grid operations processes and procedures.

The Smart Inverter Working Group is absolutely on the right track. The Group's Phase II recommendations state that communication requirements are "to be included in Rule 21, and to be include in each utility's 'Generation Interconnection Handbook', and to be included in a single "California IEEE 2030.5 Implementation Guide". All of these proposed requirements not only provide the capabilities to communicate, but also address the Company's contention that the Phase II recommendations "do not require communications to be installed to make use of these capabilities".

While wholesale DERs, by virtue of their size, present the largest potential opportunity for DER data access, the DER provider network is available for use by utilities to address loads

[73] Response to TURN-SCE-065, Q20; Response to TURN-SCE-078, Q.09.a.

masked by smaller DERs too. (The DER provider network is a general term meant to describe DER generation data communicated via the Internet to PV Solar system lessors and third party aggregators, into which the Company's grid operators could conceivably tap.) In my discussions with the California solar industry, it has become clear to me that utilities could tap into the DER provider network. Of course the solar industry would like to charge the utility for access to such data, making their claims appear self-serving. However, I agree that it would be much less costly for ratepayers to secure generation data from the DER provider network than to spend $1.275 billion to address the issues caused by failure to access DER generation data. I recommend that the Commission direct the Company, and all California investor-owned utilities, to acquire, and make good use of, wholesale and retail DER generation data in every instance in which such data is available.

Q. ARE THERE OTHER THINGS THE COMPANY COULD BE DOING TO AVOID DER-RELATED RELIABILITY CHALLENGES?

A. Yes. The Company does not appear to hold DERs, and in particular wholesale DERs, to existing technical standards which could avoid DER-related reliability challenges. In a third example of a DER-related challenge the Company experienced, obtained in discovery, the Company cites a situation involving switching, again on circuits containing large amounts of wholesale DERs.[74] In this instance, a switching procedure on a circuit with high levels of DERs resulted in voltage exceeding the high-end of the allowed voltage

[74] Response to TURN-SCE-026 Q.30.c.

range. Unfortunately, the Company does not require DERs to disconnect automatically when voltage exceeds ANSI standard C84.1.[75] Had the Company required the wholesale DER owner to disconnect automatically in out-of-range voltage situations, the wholesale DER would have disconnected from the grid and the problem would have been avoided with no grid operations automation.

Q. HOW WOULD YOU RECOMMEND THE COMPANY SPECIFICALLY ADDRESS THE DER-RELATED "MASKED LOAD-POWER FLOW" ROOT CAUSE CHALLENGE?

A. For any systems above 1MW, which would likely include all wholesale DERs, the Company is authorized to require telemetry which would provide real time access to DER generation output per Rule 21_1-J.5. I recommend the Commission direct the Company to require telemetry for every system above 1MW, and to make more consistent use of this data. To unmask loads obscured by production from smaller systems, including most behind-the-meter NEM DERs, I recommend that SCE take advantage of the DER provider network as I discussed above.

I also recommend taking advantage of the historical smart meter data available to the Company through its AMI meters, combined with the Grid Connectivity Model (GCM) the Company proposes in Information Technology Volume 2. The Company claims the GCM will "serve as the single, centralized source of connectivity information for all

[75] Responses to TURN-SCE-123 Q.13.e.

assets—from bulk generation down to the end-consumer meters. This new software model will support other enterprise tools that require the use of SCE's electric system connectivity information and the operational configuration of devices."[76] I recommend using the GCM, in conjunction with historical smart meter data, to develop a model of historical loads for all sections of the grid for every hour of the year. Smart meters provide hourly usage data on all premises, and the GCM could be used to "roll-up" this highly granular data into hourly load estimates for each section of the Company's distribution grid. I appreciate that the hourly load estimates may not be a precise representation, since customer loads will vary from year to year. However, given that there are typically 1,000 customers on each circuit, and given that retail NEM systems are small, any such estimates are likely to be close enough for grid operators to complete their grid state estimates and switching plans. Be reminded that this statement assumes the Company will require, access, and make use of data from wholesale DER systems in near-real time as authorized by Rule 21_1-J.5; and, through a cooperative effort with the solar industry, to take advantage of the DER provider network.

With this model of likely loads for any section of the grid for any hour of any day, and the generation information for both wholesale and retails DERS, combined with the GMS (or the less costly ADMS/DERMS solution I propose later in this testimony), the Company should have everything it needs for grid state estimation and switch planning. (As I will address later, the ADMS/DERMS software offers all of the essential components of the GMS software but for the automation.) Effective use of: 1) the GCM/Smart meter data

[76] Information Technology volume 2, page 161, line 20 to page 162, line 2.

model; and 2) the real-time wholesale (and eventually retail) DER generation data; and 3) the GMS (or the ADMS/DERMS I recommend); will give the Company all the capabilities it requires to address power flow and masked load root causes related to DERs. Note that these root causes can be addressed without grid operations automation, which is to say without the Company's DA, FAN, WAN, or GMS proposals.

Q. DO YOU HAVE OTHER "BIG PICTURE" PERSPECTIVES TO SHARE ON THE GRID OPERATIONS AUTOMATION?

A. No. I have provided context sufficient for readers to understand my observations and alternative recommendations to the Company's DA, FAN, WAN, and GMS proposals.

2. OBSERVATIONS ON, AND ALTERNATIVES TO, DA, FAN, WAN, & GMS

Q. PLEASE DESCRIBE YOUR OBSERVATIONS ON, AND ALTERNATIVE RECOMMENDATIONS FOR, THE COMPANY'S GRID OPERATIONS AUTOMATION PROPOSAL, BEGINNING WITH DISTRIBUTION AUTOMATION.

A. The Company's distribution automation (DA) proposal involves the use of remote intelligent switches (RIS) and remote fault indicators (RFI), in conjunction with grid management system (GMS) software, to automate the execution of grid reconfiguration.

But as described earlier, a grid with high levels of DER can be reconfigured without grid operations automation using a combination of modeled smart meter data, GCM and ADMS/DERMS applications, and better transparency to DER output data. The question becomes, is the incremental benefit of grid operations automation worth its incremental costs?

As presented in Table 2 in the Preview, the Company's capital requests related to grid operations automation amount to $1.275 billion. However, the incremental benefits of this investment are nebulous, to say the least. In discovery, I asked the Company to estimate incremental DER accommodation benefits the Company cited in testimony. The Company stated it had not estimated, and was therefore unable to provide estimates on:

- The incremental DER capacity the proposals would enable the Company to reliably accommodate;[77]
- The reduction in DER curtailment the Company's proposals offer.[78]

A failure to provide these estimates causes me concern about the incremental benefits of the Company's grid operations automation proposal. The Company does provide estimates regarding the incidental reliability benefits of automating grid operations on circuits targeted due to high levels of DERs. However, despite the Company's claims to the contrary, these benefits are clearly insufficient to justify the company's grid operations automation investment.

[77] TURN-SCE-107 Q.13.b

[78] TURN-SCE-026 Q.04.h

The Company cites incremental reliability benefits from its automation of the first 88 DER-related circuits as 1.5 million customer minutes and 15,000 customer interruptions annually.[79] Using the Company's own valuations of $2.32 per customer minute and $91.05 per interruption, and assuming a 30-year circuit lifespan, the present value of these benefits (discounted at 7.9 %) is $50.0 million. However, the cost of automating the 88 circuits required to deliver these benefits is $95.25 million (88 circuits @ $1.0937 million each), meaning that customers will pay at least $1.90 for every $1 invested in grid operations automation for circuits targeted due to high levels of DERs. Furthermore, this "cost" does not include the cost of supporting investments such as the FAN, WAN, SA-3/CSP, and GMS, nor associated carrying costs (interest, profits, and taxes on profits) on ratebase. In short, the 5-year payback the Company claims is nowhere near accurate for circuits targeted due to high levels of DERs, and TURN witness Mr. Jones has reached a similar conclusion for the reliability benefits on WCR circuits.

Instead, consistent with TURN witness Mr. Jones's testimony on DA for reliability, I propose the Company expand its use of remote controlled switches (RCS) and remote fault indicators (RFIs) to facilitate the more frequent changes to grid configuration needed to accommodate more DERs. There are two significant advantages to using RCS and RFI over the Company's DA proposal:

- RCS and RFI are proven technologies the Company and its grid operators use today, and is therefore more likely to deliver DER-accommodation benefits;

[79] Grid Modernization Volume, page 57, lines 3-6.

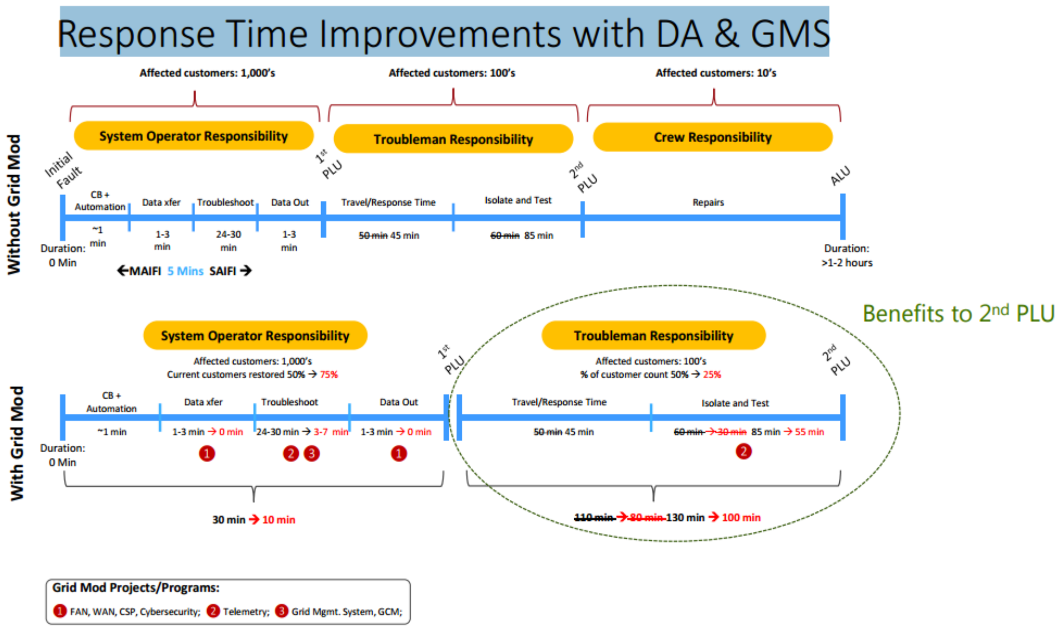
- RCS and RFI require none of the expensive support technologies (FAN, WAN expansion, GMS) which the Company's grid operations automation solution requires.

Q. WOULDN'T THE REMOVAL OF AUTOMATION CAPABILITIES ALSO RESULT IN THE REMOVAL OF AUTOMATION BENEFITS?

A. Yes, but I believe the majority of benefits from the Company's proposals stem from increased grid flexibility, as enabled by remote control switches (RCS) and remote fault indicators (RFIs), NOT from grid operations automation. The incremental benefits of automation are small, relatively speaking, especially in light of the huge incremental costs. I would like to use an example to illustrate the point that grid flexiblity, through the use of remotely read and controlled equipment, offers most of the reliability benefits at a greatly reduced cost. I have examined the example diagrams in SCE's "2nd Part Load Up (PLU) Response Time Reduction Methodology", provided in discovery.[80] The diagram below appears on page 2 of the methodology.

[80] Response to TURN-SCE-052 Question 3.d.i.3

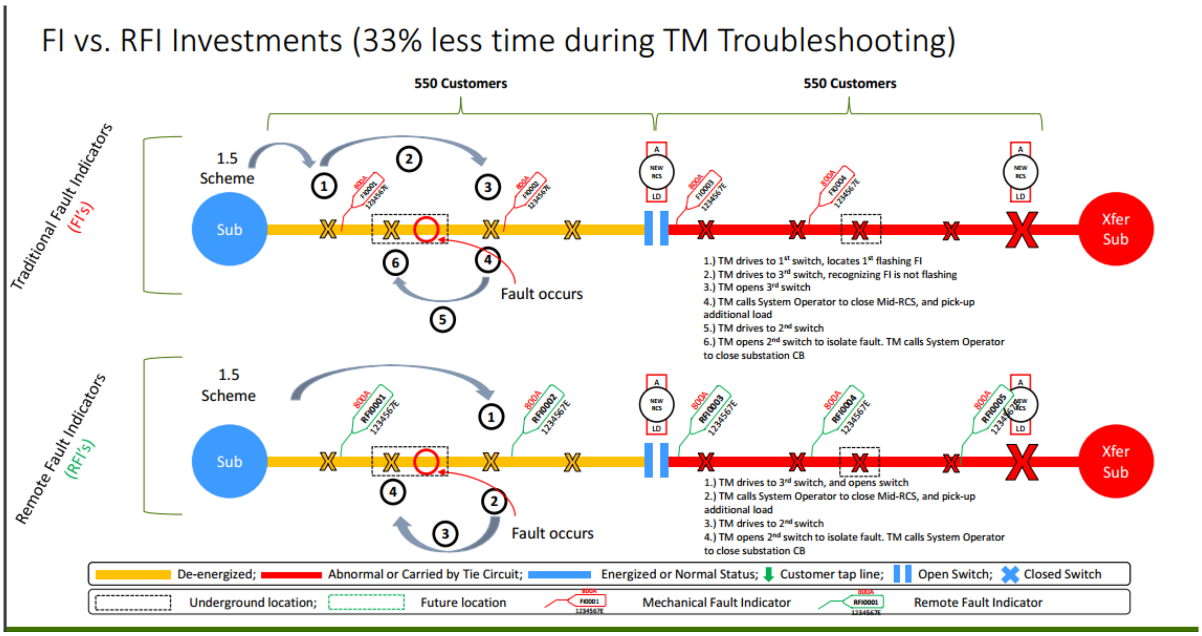
Figure 1: "Response Time Improvements from DA and GMS"



The "System Operators Responsibility" area of this diagram indicates an improvement of 20 minutes using Telemetry and GMS over the traditional method of Trouble Shooting. I will show that this savings is not due to advanced equipment telemetry or due to GMS.

In the problem analysis pages starting on page 6 of this document, the Company describes its proposal to replace traditional fault indicators, which must be observed visually in the field, with remote fault indicators, or RFIs, which can report data over the NetComm network back to grid operators.

Figure 2: Traditional Fault Indicator vs. Remote Fault Indicator Benefits



The Company indicates that telemetry and GMS delivered a 20-minute savings in analysis time (Trouble Shooting), when the savings are primarily due to installation and use of RFIs. The telemetry necessary to gather information from RFIs need not be sophisticated; it certainly does not require FAN. The data volumes are small and the number of RFIs is low. The analysis of this data certainly does not require the horsepower of a GMS; a grid operator can easily look at the information from a set of RFIs on his computer and rapidly determine the location of a fault. Most of the time savings stems from the fact that the grid operators can identify fault locations in just a few minutes using RFIs, whereas without RFIs linemen must drive from fault indicator to fault indicator looking for visual confirmation. This is the way linemen routinely locate faults in the field today. The time savings has nothing to do with advanced equipment telemetry or GMS analysis, and everything to do with reducing the time required for a lineman to drive around looking for the source of a fault (trouble shooting). With RFIs, linemen can be directed immediately to the right switches to throw, or for even faster execution, the grid operator can send instructions to throw a remote-controlled switch (RCS) from his or her computer.

I'd like to use these findings to place the Company's projected reliability benefits from grid operations automation into perspective, as the Company's reliability benefit projections represent another example of an exaggerated claim. While I do believe the Company's reliability benefit projections to be aggressive, the level of benefit projected is not the issue I will address. My issue is with the Company's claims about the *source* of these benefits. The Company claims it projected reliability benefits stem from grid operations automation. However, the exercise immediately above indicates likely due to other less costly system additions like RFIs and remote controlled switches, which I and TURN witness Mr. Jones in his testimony recommend.

Also remember, as discussed by Mr. Alvarez in the Preview, and in my perspective comments at the beginning of this section of my testimony, the benefits of grid operations automation will be difficult to secure, are therefore highly variable, and cannot be assumed to follow automatically from automation investment. It follows that while the incremental benefits of automation are relatively small, the likelihood that the benefits will actually be delivered is also small. It further follows that automation does not provide adequate incremental benefits relative to incremental costs of $1.275 billion.

Q. ASSUMING YOUR FLEXIBLE GRID/RCS SOLUTION IS PREFERABLE TO THE GRID AUTOMATION OPERATIONS SOLUTION, DO YOU HAVE ANY

OBJECTIONS REGARDING THE EXTENT TO WHICH THE COMPANY PROPOSES TO EXPAND SWITCHING CAPABILITIES (DUE TO DER)?

A. Yes, I do. The Company proposes expanding its (automated) switching capabilities to 263 circuits during the GRC period due to increasing DERs. It categorizes these circuits into one of three types:

- Expansion due to organic DER growth (63 circuits)
- Expansion due to the promotion of optimal DER locations (126 circuits)
- Expansion due to distribution capital project deferral pilots (74 circuits)

I would like to discuss the appropriateness of each of these expansions individually. I'd also like to take this opportunity to highlight the difference between my testimony and that of ORA witness Mr. Roberts. Mr. Roberts recommends rejecting the entire distribution automation program for DERs as premature based on the fact that the distribution resource plan rulemaking intends to provide future guidance on grid modernization. I agree with Mr. Roberts's recommendation. However, if the Commission accepts SCE's assertion that it must address some operational challenges during this rate case cycle, prior to DRP guidance, my testimony provides a better path based on a full review of the actual needs, benefits, and costs of the Company's grid operations automation proposal.

Q. PLEASE PROCEED, BEGINNING WITH YOUR DISCUSSION OF THE EXPANSION OF (AUTOMATED) SWITCHING CAPABIITIES TO 63 CIRCUITS DUE TO ORGANIC DER GROWTH.

A. In discovery, the Company reported the capacity of wholesale DERs connected to the Company's grid, identifying the circuits (or substations) to which these DERs were connected, as well as the capacity of retail DERs connected.[81] The Company also provided a list of the 63 circuits identified for expanded (automated) switching capabilities.[82] I examined this data, observing that of the 63 circuits, 9 served large wholesale DERs. On these 9 circuits, wholesale DER capacity exceeded retail DER capacity by a ratio of almost 32 to 1. Three of these 9 circuits had no retail DER capacity at all. Even on the circuit with the most retail DER capacity, the ratio of wholesale DER capacity to retail DER capacity was almost 12 to 1. I believe there is no way to escape the conclusion that the need for expanded switching capabilities on these 9 circuits is caused by wholesale DERs, not retail.

Per Rule 21, the cost of grid upgrades required due to wholesale DERs are to be charged to wholesale DER owners at cost. As a result, I believe the cost of expanded DER switching capabilities due to DER should be limited to 54 circuits, and that the RCS/RFI solution rather than the grid operations automation solution be applied.

Q. WHAT DO YOU THINK OF THE COMPANY'S PROPOSAL TO ADD (AUTOMATED) DISTRIBUTION SWITCHING CAPABILITIES TO 126

[81] Responses to TURN-SCE-09 Q.06.c through Q.06.h.

[82] Response to TURN-SCE-107 Q.04

CIRCUITS TO PREPARE FOR DER GROWTH RESULTING FROM THE PUBLICATION OF "OPTIMAL DER LOCATIONS"?

A. I think the Company's proposal to add distribution switching capabilities to 126 circuits to prepare for DER growth resulting from the publication of "Optimal DER Locations" is unwarranted. The Company describes two objectives it used to determine the optimal placement of DERs:[83]

- Expected DER output to reduce peak load. That is, the coincidence of an asset's (such as a substation, transformer, or circuit) load profile with the projected generation output of a given resource—solar PV or energy storage, as examples;
- Maximum substation or line utilization.

I understand why the Company has chosen this approach to prioritize optimal DER locations, but I don't see how the availability of optimal DER location information will encourage more customers in these locations to add DERs to their facilities, or to add more DERs to their facilities than they otherwise would. While the Company appears to believe that the publication of optimal DER locations will result in some sort of rush to install DERs in those locations, I think there is no reason to expect customer DER installations to be any different in these locations than in other locations. In other words, I believe the Company will see the same DER adoption in these locations as others, and that expectations of anything more than average DER growth in these locations is unsupported. The only reasonable outcome is that wholesale developers might be more interested in siting DERs in locations where ratepayer-funded upgrades have already been completed,

[83] Workpaper WPSCE02V10-R.Ragsdale. Page 67.

thereby reducing the interconnection costs wholesale developers would otherwise incur. However, Rule 21 is intended to assign the cost of wholesale DER accommodation to wholesale DER developers, not ratepayers.

As a result of these observations, I do not believe any increase in distribution switching capabilities for these 126 circuits is called for. If the Company's future forecasts indicate that "Organic DER Growth" on these circuits necessitates an increase in distribution switching capabilities, it can propose capital for such capabilities – ideally employing the RCS/RFI approach -- as needed in future rate cases.

Q. WHAT DO YOU THINK OF THE COMPANY'S PROPOSAL TO ADD (AUTOMATED) DISTRIBUTION SWITCHING CAPABILITIES TO 74 CIRCUITS IN PREPARATION FOR DER GROWTH RESULTING FROM DISTRIBUTION PROJECT CAPITAL DEFERRAL OR AVOIDANCE PILOTS?

A. I believe the Company's proposal to add distribution switching capabilities to 74 circuits in preparation for DER growth resulting from distribution project capital deferral or avoidance pilots is flawed for several reasons, which I will describe further below:

- First, under the Company's proposal, the cost to add (automated) distribution switching capabilities to these 74 circuits exceeds the cost of the distribution projects the Company is attempting to defer or avoid by a ratio of at least 2 to 1;

- The Company describes its intent to issue RFPs to procure the large amounts of DER capacity required to avoid or defer distribution project capital, which is likely to attract a great proportion of wholesale DER developers relative to retail DER;
- The risk that the incremental cost of the DER capacity procured, the incremental cost of the Company's 74-circuit automation proposal, and the cost of the distribution projects (in the event the pilot is unsuccessful) will all be incurred, and need to be recovered, falls on ratepayers;
- The fact that the Company does not know from where the DER capacity will be obtained means that any switches installed in advance will be sub-optimally located.

Before I begin, I'd like to clarify that I have no conflict with ORA witness Mr. Roberts's testimony regarding these pilots. Mr. Roberts's testimony makes very valid points regarding the lack of justification for introducing pilot projects designed to address exactly the same issues as are being addressed in multiple other pilots, including the pilots authorized in R.14-10-003 specifically intended to evaluate the potential of DERs to defer or avoid distribution project capital. My recommendations are separately based entirely on an evaluation of the need, costs, and benefits of the Company's proposed automation of grid operations.

First, I'd like to address the questionable cost-benefit analysis of the pilots. According to the Company, the cost of adding Distribution Automation to accommodate high amounts of DERs is $1.0937 million per circuit in 2018.[84] Thus, the cost for 74 circuits is $80.9 million, not including the incremental cost of DER electricity over the standard variety, not including the costs of supportive technologies such as the FAN, WAN, or GMS, and not including interest and profits on capital, or taxes on profits. The cost of the distribution projects the DER procurement and distribution automation seeks to defer or avoid is $40 million,[85] meaning that even if every one of the pilots is successful, ratepayers will pay more than $2 for every $1 saved. If this is the case, it calls into question the entire notion that DERs can help avoid or defer distribution capital investment. Indeed, this example illustrates Mr. Alvarez's observation, noted in his Preview, that the more cost-effectively DER can be reliably accommodated, the greater the role DERs can play in achieving California's environmental goals and in avoiding distribution capital projects.

Second, in workpapers the Company describes the use of a procurement process to obtain the DER capacity necessary for the distribution project capital deferral pilots.[86] As the average size of the DER capacity necessary to avoid or defer each of the distribution projects is large – 10.1 MW on average[87] -- the procurement process is likely to attract wholesale DER project developers. If the procurement process results in wholesale DER project construction, the cost of associated DER upgrades, such as the cost of grid operations automation, should be borne by the wholesale DER developers, not ratepayers,

[84] Grid Modernization volume, ERRATA, Table III-7, page 42.

[85] System Planning volume, page 48, line 2.

[86] Workpaper WPSCE02V03RBkA-E.Takayesu. Page 10.

[87] Ibid, pages 11-15.

per Rule 21. In addition, if a third party is able to aggregate many smaller new or existing retail projects on these circuits to provide some peak-reduction capacity service, then it is unclear why any additional circuit upgrades would be at all necessary.

Third, it is entirely possible that the Company will not be able to procure sufficient DER capacity to avoid or defer the distribution projects. In such an event, all or part of the originally proposed distribution projects will need to be completed anyway.[88] This would require ratepayers to pay for distribution automation, the incremental cost of energy from DERs over the standard variety, and the cost of the originally proposed distribution projects. It does not seem reasonable that ratepayers bear all of these risks.

Fourth and last, because the Company is proposing to install the Remote Intelligent Switches, and associated tie lines, presumptively – before it knows where the DER will be located – the switches and tie lines will very likely be installed in sub-optimal locations. In discovery, in reporting the results of small-scale automation testing, the Company states "Improvement could be realized for any particular outage only if existing automation equipment were installed at advantageous locations relative to the fault . . . . For example, the Autry 12kV (circuit) experienced two outages between 1/1/13 and 12/31/15 where a GMS could have been of value. However, in both cases, the location or nature of the faults precluded the possibility of GMS enabling faster restoration."[89] I believe it makes little sense to install switches and tie-lines before DER is installed and optimal locations for switches and tie-lines identified.

[88] Ibid, page 10.

[89] Response to TURN-SCE-078 Q.28.

Due to all these reasons, I believe the Company's proposal to automate the operation of 74 circuits in advance of distribution project capital avoidance pilot DERs be rejected.

Q. WHAT IF THE COMMISSION SEES VALUE IN AUTOMATING SOME CIRCUITS FOR DER PROCUREMENT PURPOSES?

A. If the Commission authorizes any of the pilots proposed in this rate case, I recommend the RCS/RFI approach be used to reliably accommodate DERs procured for the pilot in place of the Company's dramatically more costly grid operations automation approach.

Q. COULD YOU PLEASE SUMMARIZE THE FINANCIAL IMPACT OF YOUR RECOMMENDATIONS TO THE COMPANY'S CAPITAL REQUST FOR DA?

A. Yes. Please see the summary table below.

Table 7: Summary of recommended adjustments to the Company's DA capital request.

($ in millions)	Test Year	GRC Period
Reject the Company's Distribution Automation proposal[90]	($96.3)	($296.8)
Add RCS and tie lines to 54 circuits at $621,000[91] per circuit	11.2	33.5
Net reduction to the Company's DA Capital Request:	($85.1)	($263.3)

[90] Grid Modernization volume, ERRATA, Table III-12, page 40a.

[91] Workpapers in support of testimony provided by Garrick Jones on behalf of TURN.

Q. WHAT ARE YOUR OBSERVATIONS ON, AND ALTERNATIVE RECOMMENDATIONS FOR, THE COMPANY'S FIELD AREA NETWORK PROPOSAL?

A. The Company proposes to spend $199.2 million in the GRC period to complete just the first phase of its NetComm field communications network replacement project, covering only about 40% of the Company's service territory.[92] The Company cites multiple needs for the NetComm replacement, including:[93]

- The FAN supports the device-to-device, sub-second latency communications required by the Company's grid operations automation proposal;
- The NetComm network is slow, and reaching its maximum capacity; and
- The NetComm network is subject to future, unspecified cybersecurity risks.

If the Commission decides to reject the Company's proposal to automate distribution operations consistent with my recommendations, the FAN is not necessary.[94] The NetComm network can continue to communicate with RCSs and RFIs as it does today. Regarding the speed and capacity of the NetComm network, the Company admitted in discovery that communications speed and capacity could be increased simply by adding more NetComm data collection points.[95] The Company also describes in testimony that

[92] Workpaper WPSCE02V10-R.Ragsdale. Page 78.

[93] Grid Modernization volume, pages 74-76.

[94] Response to TURN-SCE-078, Q.15.a and Q.15.b.

[95] Response to TURN-SCE-026, Q.49.

the NetComm network is secure, and that the Company has been able to upgrade the cybersecurity of the NetComm network to date.[96]

If the Commission decides to reject the Company's proposal to automate distribution operations, I believe it should also reject the Company's FAN proposal. However, I appreciate the Company's need to expand and secure the NetComm network. In the event the Commission rejects the Company's FAN proposal, I recommend the Commission permit the Company to increase the Company's proposed NetComm capital budget (DSEEP) beyond what the Company has requested. The Company spent an average of $4.4 million per year for NetComm capital from 2011 to 2015, and proposes an average 40% increase from 2016 to 2020 (or $6.15 million per year on average). To accommodate NetComm expansion and cybersecurity upgrades, I propose an increase of 60% over historical spending, or an average of $7.0 million per year through the GRC period. I summarize my recommended adjustments to the Company's proposed FAN capital request in the table below.

Table 8: Summary of recommended adjustments to the Company's FAN capital request

($ in millions)	Test Year	GRC Period
Reject the Company's Field Area Network proposal[97]	($14.8)	($199.2)
Increase the Company's NetComm capital request (DSEEP)	0.6	1.9
Net reduction to the Company's FAN capital request:	($14.2)	($197.3)

[96] Grid modernization volume, page 77, line 4.

[97] Grid Modernization volume. Figure III-24. Page 73.

Q. WHAT ARE YOUR OBSERVATIONS ON, AND ALTERNATIVE RECOMMENDATIONS FOR, THE COMPANY'S WIDE AREA NETWORK PROPOSAL?

A. Like the FAN proposal, the Company's proposal to expand its wide area network (WAN) is largely predicated on the proposal to automate grid operations. In its request to expand and improve the WAN, the Company cites increased bandwidth needs demanded by the grid operations automation proposal as well as the SA-3/CSP (substation control system) upgrade proposal (to be discussed further below).

In discovery, the Company conceded that without grid operations automation, the FAN will not be needed,[98] and that without automation, the FAN, or the SA-3, the WAN expansion will not be needed.[99] Therefore, if the Commission accepts my recommendation to reject grid operations automation, and by extension the FAN, and if the Commission accepts my recommendation for advanced SAS-2 instead of SA-3, the Commission should also accept my recommendation to reject the WAN expansion. Such a rejection would reduce the Company's Volume 10 capital request by $39.0 million in the test year and $116.6 million over the GRC period.[100]

[98] Response to TURN-SCE-078 Q.15.a

[99] Response to TURN-SCE-078 Q.17.a and Q.17.b.

[100] Grid Modernization volume, Figure III-29. Page 82.

Q. PLEASE COMPLETE YOUR OBSERVATIONS ON, AND ALTERNATIVE RECOMMENDATIONS FOR, THE COMPANY'S AUTOMATION PROPOSAL BY ADDRESSING THE GRID MANAGEMENT SYSTEM.

A. The final component required for grid operations automation is the grid management system, or GMS. The Company proposes to use the GMS to initiate and send instructions over the WAN and FAN to open and close remote intelligent switches via the substation control system (SA-3/CSP). In so doing, the GMS automatically reconfigures the grid based on information provided by various software applications and networks, including the Grid Analysis Application, the Grid Connectivity Model, and the DER Provider Network, to name but a few. The Company also proposes to integrate existing systems and capabilities, such as the Outage Management System, the Distribution Management System, and SCADA (supervisory control and data acquisition system), with the new GMS. In general, like the FAN and the WAN, the value of a GMS is predicated on the approval of distribution automation. However, unlike the FAN and the WAN, the Company would not confirm in discovery that the GMS is of no benefit without automation, claiming GMS is required for regulatory requirements associated with the procurement and integration of distributed storage.[101]

I can appreciate that the Company's current distribution management system (DMS) is not up to the task of supporting a distribution grid operated in the presence of high levels of DERs. I am familiar with the Company's current DMS, GE's PowerOn®, and its

[101] Response to TURN-SCE-078 Q.18.

limitations. On the other hand, I cannot condone the deployment of a $135 million GMS in the event its primary intended function – grid operations automation – is rejected by the Commission as I recommend. Instead I recommend the Company consider, and the Commission approve, a smaller amount of capital for the next step along the way to grid operations automation: an advanced distribution management system, or ADMS, combined with a DER management system, or DERMS.

I have seen that ADMS and DERMS software offer all of the most critical functions of a GMS except the automation, including grid state estimation, power flow analysis, switching simulation, outage management, SCADA system interface, fault location, volt-VAr control, thermal ratings, and many more. ADMS can be paired with commercially-available DERMS software applications offering real time DER generation data access, analysis, planning, and control functions (including the integration of distributed storage).

While the capital cost to implement an ADMS/DERMS solution is difficult to predict, it is likely far less than the cost to implement a GMS. In addition, as an ADMS/DERMS solution does not offer grid operations automation, it is less subject to cost overruns. I will make a rough guess as to the cost to implement an ADMS/DERMS solution here, but admit my estimate is based on limited information of the Company's systems, suppliers, and information technology approaches. In the interest of providing some type of starting point, I estimate the cost to implement an ADMS/DERMS solution to be $60 million. I would welcome the critique and input of Company personnel to better hone this estimate.

From a ratemaking perspective, it could make sense to either authorize a balancing account, or require the Company to submit a new application, for the ADMS/DERMS solution. As I am a technical operations expert, not a ratemaking expert, I am not offering a recommendation on this issue.

Table 9: Summary of recommended adjustments to the Company's GMS capital request

($ in millions)	Test Year	GRC Period
Reject the Company's Grid Mgmt. System proposal[102]	($39.8)	($122.4)
Provide capital to implement an ADMS/DERMS solution	20.0	60.0
Net reduction to the Company's GMS capital request	($19.8)	($62.4)

3. VOLUME 10 COMPONENT OF THE SA-3 PROPOSAL

Q. PLEASE COMPLETE YOUR OBSERVATIONS ON, AND ALTERNATIVE RECOMMENDATIONS FOR, THE COMPANY'S SA-3 PROPOSAL.

A. As described in my Volume 6 testimony on the Company's SA-3 proposal, I do not agree that frequent, dynamic adjustments to circuit breaker settings are necessary to accommodate DER-related grid reconfigurations, or for grid reconfigurations for other purposes. I will not repeat that testimony here. To summarize, as in my Volume 6 testimony, I recommend the CSP components of the Company's SA-3/CSP proposal be approved, but that the SA-3 component be rejected. The Volume 6 and Volume 10 substation control system technologies are the same; the only difference is that the new SA-3/CSP standard is proposed to support grid operations automation in Volume 10, and simply to replace aging equipment in Volume 6.[103] Regardless of the reason for the

[102] Grid Modernization volume. Figure III-34. Page 99.

[103] Response to TURN-SCE-061 Q.10.c.

upgrade, however, I believe only the CSP components of the SA-3/CSP approach are needed for reliable grid operations.

My Volume 6 testimony explains in full my recommendations, and I will not repeat those explanations or associated capital reductions here. However, the capital request reductions I am recommending in Volume 10 are far greater than those in Volume 6 for two reasons. First, the Company only proposes to upgrade 65 substations in Volume 6, while upgrades are proposed for 92 substations in Volume 10. Second, the Company requests $827,000 for each substation upgrade in Volume 6, but between $2.45 and $3.15 million per substation in Volume 10.[104] Below please find a summary of recommended adjustments to the Company's SA-3/CSP proposal.

Table 10: Summary of recommended adjustments to the Company's Volume 10 SA-3/CSP capital request

($ in millions)	**2018**	**GRC Preiod**
Reject the Company's SA-3/CSP proposal[105]	($106.7)	($313.9)
Add back capital required for CSP and equipment housing ($193,300 and $25,000 per substation per Volume 6 testimony)	6.8	20.1
Net reduction to the Company's SA-3/CSP capital request:	(99.9)	(293.8)

[104] Response to TURN-SCE-026 Q.35.

[105] Grid Modernization volume. Figure III-18. Page 60.

4. OVERALL CONCERNS WITH THE COMPANY'S GRID MODERNIZATION PLANNING AND BENEFIT ESTIMATES

Q. DO YOU HAVE OVERALL CONCERNS WITH THE COMPANY'S GRID MODERNIZATION PLANNING PROCESS YOU WISH TO SHARE?

A. Yes, I have an overall concern that the Company's process for identifying and implementing grid operations automation does not comport with standard utility practices. As Mr. Alvarez stated in the Preview, there is a standard approach distribution utilities have used to resolve problems in grid operations for about a century now. It appears to me that the Company failed to apply this approach in its decision to pursue grid operations automation and the selection of circuits for DER-related distribution automation deployment.

While the Company will likely argue that the proliferation of DERs is different, and requires a departure from standard practice, I would ask them in advance to provide support for how DER proliferation is different, and why it requires such a departure. While DER is new, I submit the reliability challenges it presents on an incremental, circuit-by-circuit basis, including the root causes of power flow and load masking, are not new and do not justify a departure from standard practice. Throughout its grid modernization proposal, the Company demonstrates departures from the standard practice time and again.

- Rather than waiting for a problem to occur, the Company develops hypothetical problems which might occur under a set of circumstances that are extremely unlikely and impossible to predict. The former is not reactive, it is pragmatic. The latter is not proactive, it is presumptive. There is a difference.
- Rather than identifying the root causes of a problem that has occurred, the Company jumps to solutions to hypothetical problems. The former is rooted in the scientific method, while the latter is likely to waste time, money, and effort.
- Rather than identifying a variety of approaches to addressing the root causes of a problem, and testing each for effectiveness and practicality, the Company presents a single, untested approach. The former is logical, while the latter is risky.
- Rather than implement a proven, cost-effective approach as needs are encountered locally, and as prioritized by a risk-informed merit process, the Company proposes to implement an unproven, capital-intensive solution across wide swaths of its extremely large service area. I'd characterize the Company's automation proposal as presumptive, likely wasteful, and very risky.

5. SUMMARY OF GRID MODERNIZATION TESTIMONY

Q. PLEASE SUMMARIZE YOUR GRID MODERNIZATION TESTIMONY.

A. In my grid modernization testimony, I began by providing some context and perspective for the Company's grid operations automation proposal. In this introduction I:

- Provided an overview of the grid state estimation and reconfiguration process;
- Identified the root causes behind the reliability challenges of DERs as presented in the Company's hypothetical examples, namely power flow and masked load;
- Raised questions as to whether the Company's grid operations automation proposal represented the best approach to addressing power flow and masked load.

I then addressed each of the components associated with the Company's proposal to automate distribution operations, including DA, FAN, WAN, and GMS. I began by making a distinction between grid flexibility and its benefits, and grid operations automation and its benefits.

- As to technology selection, I recommended the use of remote controlled switching (RCS) and remote fault indicators (RFI) rather than automated switching;
- As to circuit selection, I validated 54 circuits for RCS due to organic DER growth, while rejecting 9 circuits as primarily serving wholesale DERs;
- I recommended upgrades be rejected for 126 "optimal DER location" circuits, as these circuits do not appear to meet the organic DER growth standard;
- I recommended upgrades be rejected for 74 "distribution project capital deferral pilot" circuits, due primarily to the fact that costs outweigh benefits by 2 to1;
- I recommended FAN, WAN, and GMS be rejected due largely to the fact that their needs are predicated as support for grid operations automation.

I then repeated in Volume 10 what I recommended in Volume 6: that my advanced SAS-2 proposal for substation control systems delivers needed capabilities and cybersecurity at a fraction of the cost of the Company's SA-3/CSP proposal. Finally, I described my overall concerns about the lack of standard problem-solving processes I believe to be apparent in the Company's decision to pursue grid operations automation as the best solution to DER-related reliability challenges.

In conclusion, I recommend that the Commission reject grid operations automation in favor of increased grid flexibility through remote controlled switches and remote fault indicators, accommodating more DERs at lower cost with a greater likelihood the investments will deliver anticipated benefits.

VI. SUMMARY AND CONCLUSIONS (ALVAREZ)

Q. PLEASE SUMMARIZE YOUR JOINT TESTIMONY

A. In this testimony Mr. Stephens and I have made the case that most of the capital spending the Company proposes to reliably accommodate more DERs is unwarranted.

The first recurring theme we've documented is that the Company routinely exaggerates the risks, rewards, and requirements (regulatory or operational) associated with its proposals. Primary examples include:

- The Company confuses the Commission's instruction to reliably accommodate more DER as a mandate to automate grid operations; and
- The Company routinely uses hypothetical examples to illustrate problems that might occur, rather than identifying the true root causes of DER-related reliability challenges.

The second recurring theme we've documented is that the Company proposes capabilities whose incremental costs are dramatically out of proportion to incremental benefits. Primary examples include:

- The elimination of 4kV substations and circuits (for reasons other than overload) cost customers at least $3.04 for each $1 in benefit;
- The Company claims automation delivers substantial DER accommodation benefits, when those benefits are more appropriately attributed to grid flexibility, whether automated or not. Relatively small incremental benefits are available from

grid operations automation, but these are insufficient to justify the enormous incremental costs.

- We identified multiple instances where the cost of DER accommodation should have been borne by wholesale DER owners rather than added to the ratebase.

The third recurring theme we've documented is that the Company's proposals make no attempt to rein in DER accommodation costs, proposing high-cost approaches in instances where lower-cost approaches are available. Primary examples include:

- The "alternatives" the Company describes actually present false choices between spending large amounts of capital and accommodating fewer DERs, while low cost approaches to accommodating more DERs are not presented as alternatives;
- The Company fails to use existing or developing standards to avoid problems or capital investment, as indicated by the Company's failure to access and use near-real time data available from large DER facilities;
- The Company fails to use proven industry approaches to identifying and prioritizing grid investments with the greatest risk reduction potential as indicated by risk-informed investment merit processes. Failure to employ these processes results in the selection of high-cost, low-benefit solutions such as 4kV elimination and grid operations automation.

Q. DOES THIS CONCLUDE YOUR JOINT TESTIMONY?

A. (Alvarez) Yes, it does.

A. (Stephens) Yes, it does.

APPENDICIES

A. Alvarez Curriculum Vitae

B. Stephens Curriculum Vitae

Curriculum Vitae -- Paul J. Alvarez MM, NPDP

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Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed the limitations of current utility regulatory and governance models. Mr. Alvarez currently serves as the President of the Wired Group, a boutique consultancy serving consumer and environmental advocates, regulators, associations, and suppliers.

Research Projects, Thought Leadership, Regulatory Appearances

Arguments to Reject Aspects of National Grid's Grid Modernization Plan. Testimony before the Massachusetts Department of Public Utilities on behalf of the Attorney General, case 15-120. March 10, 2017.

Arguments to Reject Aspects of Unitil's Grid Modernization Plan. Testimony before the Massachusetts Department of Public Utilities on behalf of the Attorney General, case 15-121. March 10, 2017.

Arguments to Reject Aspects of Eversource's Grid Modernization Plan. Testimony before the Massachusetts Department of Public Utilities on behalf of the Attorney General, cases 15-122 and 15-123. March 10, 2017.

Arguments to Reject the Smart Meter Deployment Plans of Kentucky Utilities and Louisville Gas & Electric. Testimony before the Kentucky Public Service Commission on behalf of the Office of Attorney General, cases 2016-00370 and 2016-00372. March 3, 2017.

Arguments to Reject Duke Energy Kentucky's CPCN for a $49 Million Smart Meter Investment in Favor of Reconsideration in a Rate Case. Testimony before the Kentucky Public Service Commission on behalf of the Office of Attorney General, 2016-00152. July 18, 2016

Arguments to Reject Pacific Gas & Electric's Request to Invest $100 Million in Its Grid to Accommodate Distributed Energy Resources. Joint testimony with Mr. Dennis Stephens before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

Arguments to Reject Westar Energy's Proposal To Mandate a Rate Specific to Distributed Generation-Owning Customers. Testimony before the Kansas Corporation Commission on Behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

Best Practices in Grid Modernization Capability Optimization: Visioning, Strategic Planning, and New Capability Portfolio Management. Top-5 US utility; client confidential. 2014.

Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

Duke Energy Ohio Smart Grid Audit and Assessment. Primary research report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

SmartGridCity™ Demonstration Project Evaluation Summary. Primary research report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. Filed December 14, 2011 as Exhibit MGL-1. Report dated October 21, 2011.

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. First edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 327 pages. 2014.

Noteworthy Publications

Integrated Distribution Planning: An Idea Whose Time has Come. Public Utilities Fortnightly. November, 2014.

Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments. Public Utilities Fortnightly. December, 2009.

Smart Grid Regulation: Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

Notable Presentations

NARUC Committee on Energy Resources and the Environment. *How big data can lead to better decisions for utilities, customers, and regulators***.** Washington DC. February 15, 2016.

National Conference of Regulatory Attorneys 2014 Annual Meeting. *Smart Grid Hype & Reality*. Columbus, Ohio. June 16, 2014.

NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando. November 18, 2013.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.* Orlando. November 17, 2013.

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Keynote. Toronto, Canada. January 23, 2013.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us.* Chicago. September 26, 2012.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012.

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25, 2012.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23, 2012.

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators.* St. Louis. November 13, 2011.

Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

Education

Master of Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Accounting, Finance, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Marketing and Finance.

Certifications

New Product Development Professional. Product Development and Management Association. 2007.

Curriculum Vitae – Dennis Stephens EE

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Profile

Mr. Stephens has over 35 years' experience in electric distribution grid planning, design, operations management, asset management, and the innovative use of technology to assist with these functions. He spent his entire career at Xcel Energy subsidiary Public Service Company of Colorado, an electric (and gas) distribution business serving over 1.2 million customers. In a series of electrical engineering and management roles of increasing responsibility, Mr. Stephens served as Director, Electric and Gas Operations for the City and County of Denver; Director, Asset Strategy; and Director, Innovation and Smart Grid Investments (for all of Xcel Energy's 8-state service territory). Mr. Stephens retired from Xcel Energy in 2011, and now works for the Wired Group on a part-time basis.

Noteworthy Projects

Arguments to Reject Pacific Gas & Electric's Request to Invest $100 Million in Its Grid to Accommodate Distributed Energy Resources. Joint testimony with Mr. Paul J. Alvarez before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

Smart Grid Solutions Development, 2010. Worked with several large solution providers to develop and implement technical distribution grid solutions and innovations, including IBM, ABB, and Siemens**.**

DER Integration Strategy and Roadmap Development, 2009. Established DER integration strategy and road-maps for Xcel Energy, including technology and capability roadmap for high DER penetration geographies in Boulder, Colorado.

SmartGridCity™ Project Development, 2008. Developed the technical foundations for the SmartGridCity project in Boulder, Colorado (46,000 customers).

Distribution Automation Design, 2007. Worked with ABB Corporation to design software to identify and locate failures in underground cable. The ABB Smart Analyzer™ was programmed with three traps to capture detailed information using Oscillography/Digital Fault Records (O/DFR).

Utility Innovations Program Development, 2006. Led the development of Xcel Energy's Utility Innovations program, for which Mr. Stephens' team receive a national Edison Award.

Distribution Asset Optimization Process, 2005. Taking advantage of SPL's Centricity Outage Management Program and Itron's Real Time Performance Management system (RTPM), developed a Distribution Asset Optimization process by mining AMI meter data and asset utilization information in the development of an enhanced asset loading forecasting process. The process took advantage of the systems' abilities to forecast sudden changes in usage patterns to take proactive mediation of equipment overloading.

Distribution Asset Optimization Software Development, 2004. Worked with Itron on the development of a Distribution Asset Optimization software program.

Fixed AMI Communications Network Development, 2003. Worked with Itron to pilot one of the first applications of a fixed wireless radio network to collect data from customer meters.

Electric Asset Management Strategy Development, 2002. Developed Xcel Energy's Electric Distribution Asset Management Strategy

Automated Switching System Deployment, 2001. Worked with S&C Electric Corporation on to deploy its Intelliteam™ devices on Xcel Energy's distribution grid to reduce the number of customers impacted by an outage by isolate faults through automated switching routines.

Regulatory Appearances

General Novelty vs. Public Service Company of Colorado. Testimony in Colorado PUC Case 6609 on behalf of Public Service regarding restitution for customer equipment damage resulting from transformer failure. Public Service Company of Colorado prevailed as a result of Mr. Stephens' testimony.

Notable Presentations

DistribuTECH 2010, Tampa, Florida. "Realizing the Benefits of DER, DG and DR in the Context of Smart Grid"

OSI 2008 User's Conference, Denver, Colorado; DistribuTECH 2007, San Diego, California. "Smart Grid City: A blueprint for a connected, intelligent grid community"

ABB 2007 World Conference, Jacksonville, Florida. "Use of Distribution Automation Systems to identify Underground Cable Failure"

North American T&D Conference 2005, Toronto, Canada; Itron 2005 User Conference, Boca Raton, Florida. "Xcel Energy Utility Innovations and Distribution Asset Optimization"

DistribuTECH 2005, San Diego, California. "How Advanced Metering Technology is Driving Innovation at Xcel Energy"

Education

Bachelor of Science Degree in Electrical Engineering, 1975, University of Missouri at Rolla.

Awards

National Edison Award for Utility Innovations, 2006.