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Witness: Paul A. Alvarez
Dennis Stephens

PREPARED TESTIMONY OF PAUL A. ALVAREZ AND DENNIS STEPHENS

ADDRESSING PACIFIC GAS AND ELECTRIC COMPANY'S DISTRIBUTED ENERGY RESOURCE INTEGRATION CAPACITY PROGRAM

Submitted on Behalf of

THE UTILITY REFORM NETWORK

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April 29, 2016

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 the Distributed Energy Resource Integration Capacity Program (the “DERIC” Program) proposed by PG&E in Chapter 13 of its PG&E-04.[1] We recommend that the Commission reject the DERIC Program proposal in its entirety, resulting in disallowances of $22.509 million in capital in 2017 and $99.762 million in capital from 2017-2019.[2] TURN witnesses Eric Borden and Garrick Jones will address other recommended disallowances in distribution capital and O&M spending, respectively.

My testimony will demonstrate that the DERIC Program PG&E proposes is not in the ratepayers' interest. Contrary to the requirements of P.U.C Section 769, I do not believe the proposal delivers net benefits to customers, nor do I believe its associated costs are just or reasonable.

(Stephens)

My testimony will demonstrate that the DERIC Program and its presumptive investment schedule is not necessary to avoid future delays in retail DER integration, and that any risk to continued integration of DERs from rejecting the DERIC Program proposal is low.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUNDS.

A. (Alvarez)

My career in the electric utility industry began 15 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

[1] PG&E-04, p. 13-29 to 13-35.

[2] These amounts are included in MWC 06 and MWC 46, as specified in PG&E-04, p. 13-35, Table 13-4.

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 boutique sustainability consulting firm MetaVu, where I utilized my M & V experience to lead two comprehensive, unbiased evaluations of smart grid deployment performance. To my knowledge these are the only two comprehensive, unbiased evaluations of smart grid deployment performance 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,[3] and an evaluation of Duke Energy's Cincinnati deployment for the Ohio Public Utilities Commission in 2011.[4]

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

[3] *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.

[4] *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.

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.

(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. HOW IS YOUR TESTIMONY ORGANIZED?

A. (Alvarez)

Our testimony will demonstrate that the DERIC Program and its presumptive investment schedule is not in ratepayers' interests as described below.

- I summarize relevant elements of California Public Utilities Code Section 769, investor-owned utility (IOU) economic incentives, and the resulting bias I find throughout PG&E's DERIC Program proposal. I believe PG&E is using unfounded reliability concerns allegedly resulting from DER growth to increase capital expenditures more quickly than necessary. I will also discuss the outsized importance of the DERIC Program proposal resulting from its potential to establish inappropriate precedents.

- Mr. Stephens will continue by describing why the DERIC Program and its presumptive investment schedule is not necessary to avoid future delays in retail DER integration, and why the risk of postponing DERIC Program investments until they may become necessary on an as needed basis is low. Mr. Stephens explains that PG&E has successfully used industry standard practices and processes to date to integrate a large amount of DER with no operational problems, and presents evidence that presumptive investments proposed in the DERIC Program are premature.

- I will resume testimony by demonstrating that the DERIC Program is much more costly to ratepayers than the industry standard practices and processes PG&E is already employing successfully. I will also describe why the DERIC Program may benefit wholesale DER owners at ratepayer expense, and present evidence that PG&E's investments would subsidize wholesale DER interconnections in violation of Rule 21. Finally, I will describe how presumptive investment transfers PG&E performance risk into ratepayer economic risk.

- I summarize the above arguments to show that the DERIC Program is not cost-effective, as it fails to provide net benefits to ratepayers, and the cost is far out of proportion to ratepayer and prospective retail DER owner risk reduction. I recommend that the Commission disallow the entire $22.5 million capital forecast for the first year of the DERIC Program (test year 2017), and order PG&E to not make these presumptive investments. I make several additional recommendations designed to promote DER integration on PG&E's distribution system during the course of this rate case.

II. PG&E IS USING THE DERIC PROGRAM TO PROMOTE UNNECESSARY CAPITAL EXPENDITURES THAT DO NOT PRODUCE NET BENEFITS (ALVAREZ)

Q. PLEASE PRESENT YOUR PERSPECTIVE ON THE ROLE OF SECTION 769 IN THE REGULATION OF CALIFORNIA IOUS.

A. I understand that Section 769 of the California Public Utilities Code directs utility investments " . . . to minimize overall system costs and maximize ratepayer benefit from investments in distributed (energy) resources (DER)." However, I view the cost-effective deployment of DER as only one of several goals the Commission advances. Others include the protection of consumers by ensuring utility services are provided safely, reliably, and at just and reasonable rates. The Commission has optimized the balance among these goals for more than a century, adding environmental enhancement as California's needs evolved. TURN and I share the Commission's interest in optimizing the balance among these goals.

For over 100 years, California IOUs have been tasked with finding the most cost-effective solutions to technical and business issues as they arise. The attainment of renewable generation goals, and DER integration in particular, simply represents new technical and business challenges that PG&E must solve in the most cost-effective manner possible. The Commission's role is to establish the governance required to ensure the challenges are met reliably, safely, and at the lowest possible cost to ratepayers, while providing economic incentives to IOU shareholders to do so.

Q. PLEASE SUMMARIZE WHY PG&E'S DERIC PROPOSAL RESULTS IN UNNECESSARY CAPITAL EXPENDITURES

A. Based on extensive evaluation of the components of the DERIC program, I find that the proposed capital investment is unnecessary for the following reasons, which are detailed in the remainder of this testimony:

- The DERIC Program proposes to invest presumptively rather than on an "as needed" basis, despite the fact that there is no evidence that continuing with "as needed" upgrades does not work, and in the face of evidence that presumptive investment will result in unnecessary and costly upgrades on circuits that would experience no problems integrating more DERs;

- The DERIC Program proposes hardware solutions with long depreciable lives over alternative solutions with reduced ratebase impact (such as short-lived software solutions or operational solutions requiring no Company capital);

- The DERIC Program proposes to add, to the ratebase, the cost of upgrades that should have been charged to wholesale DER owners, as well as the cost of upgrades that will benefit yet-to-be-identified wholesale DER owners.

Q. THE DERIC PROGRAM IS A SMALL COMPONENT OF PG&E'S GRC. WHY ARE YOU AND TURN DEVOTING TIME AND RESOURCES TO REJECT IT?

A. As this testimony will demonstrate, presumptive DERIC Program investments are not needed to avoid retail DER integration delays, and the reliability and safety risks associated with traditional "upgrade as needed" approaches is low or zero. While spending any amount of ratepayer funds on upgrades that deliver no ratepayer benefit is sufficient basis for my efforts, I believe the approval of the DERIC Program would set several bad precedents:

- It would force ratepayers to subsidize wholesale DER owners (let alone retail DER owners);

- It would approve presumptive investments to solve problems which will not appear in the near term, can be more effectively addressed on an "as-needed" basis in a more traditional manner, and might result in upgrades on circuits that will not see DER growth;

- It would approve the first phase of a program that targets less than about 16% of PG&E's circuits, and anticipates - without any explanation or justification of the potential size and need for – large future presumptive investments.

The DERIC Program will only upgrade 506 of PG&E's 3200 circuits for $75 million (MWC 06), and 5 of its 900 substations for $25 million (MWC 46).[5] Simple extrapolation of these numbers delivers full deployment cost estimates in the billions of dollars *in PG&E's service territory alone*. In discovery PG&E stated that it would not commit to the additional amount of retail DER capacity it could accommodate if DERIC Program upgrades were implemented as proposed. This means ratepayers don't know what they are getting for their money, and can't assume that more funds won't be needed to integrate DER on these 506 circuits and 5 substations. At some point, DER ceases to become a cost effective approach to reaching California's environmental goals.

Research and demonstration projects to identify more cost-effective DER integration approaches, from DER management software and smart inverters to potential use of electric storage, have not been concluded or not yet begun. In addition, the details and impact of Locational Net Benefits Analysis and associated pricing mechanisms anticipated in the Distribution Resource Planning docket (R.14-08-013) have yet to be determined, making DER growth forecasts suspect. For all of these reasons, the potential precedents that could be established by DERIC Program approval are extremely critical

[5] These amounts are included in MWC 06 and MWC 46, as specified in PG&E-04, p. 13-35, Table 13-4.

and merit careful consideration, despite the relatively minor short-term ratepayer impacts relative to the overall size of the GRC.

III. PRESUMPTIVE DERIC INVESTMENTS ARE NOT NEEDED TO AVOID FUTURE DELAYS IN RETAIL DER INTEGRATION, WHILE THE RISK OF POSTPONING DERIC INVESTMENTS IS LOW (STEPHENS)

Q. PLEASE PREVIEW THE TESTIMONY YOU ARE ABOUT TO PRESENT.

A. My testimony will demonstrate that the presumptive investment schedule of the DERIC Program is simply not needed to avoid retail DER integration delays or to avoid reliability and safety issues related to DER. I will use four arguments:

- The established distribution planning practices and processes PG&E already employs are adequate to identify significant upgrades with sufficient notice such that retail DER integration delays can be avoided, at little to no risk to reliability or safety.
- The established operating practices and processes PG&E already employs are adequate to address local voltage regulation and protective device upgrades as they arise, with little to no risk to reliability or safety.

- PG&E's practices and processes are working as intended, and have avoided reliability and safety issues as well as retail DER interconnection delays; this is true despite a number of circuits which already have very high levels of DER.

- Many if not most of the upgrades are being proposed far in advance of the time they will be required, while others are being proposed to avoid issues with little or no probability to impact distribution customers or DER owners.

Q. PLEASE PRESENT YOUR UNDERSTANDING OF THE DISTRIBUTION PLANNING PRACTICES AND PROCESSES UTILITIES USE TO IDENTIFY SIGNIFICANT UPGRADES IN ADVANCE OF NEED.

A. All utilities monitor growth in customer loads and associated impacts on Transmission, Substation and Distribution systems. They monitor trends in energy use and peak demand over time, by circuit and by substation, as part of the distribution planning discipline. The goal of distribution system planning is typically to identify, at least 2 to 3 years in advance, the need for significant distribution system upgrades. Upgrades are categorized as "significant" when they require both large amounts of capital and long lead times for design and execution. Reconductoring large sections of distribution line, substation capacity upgrades, and some substation protection upgrades can be examples of significant upgrades. They can be capital intensive and may require long lead times – about 12-18 months for some large reconductoring projects, 24-36 months in the case of substation capacity upgrade projects, and 6-12 months for some substation protection upgrades.

In geographies with excellent solar resources and extensive DER adoption such as California, the distribution planning discipline has already begun incorporating DER considerations into its work.[6] Utilities are now monitoring minimum circuit loads as well as additional DER capacity to better predict the possible occurrence of two-way power flow. These are now minimum standards for distribution planning at utilities where DER is growing.

Q. WHAT DOES THIS HAVE TO DO WITH PG&E'S DERIC PROGRAM PROPOSAL?

A. PG&E's DERIC Program proposes investing almost $20 million to reconductor 12 circuits, $19.4 million to increase the capacity of 5 substations ("upgrade substation equipment"), and $3.2 million to upgrade protective devices at the head ends of 22 circuits ("substation protection") from 2017-2019. These upgrades are significant per the definition above, and fall into the domain of distribution planning processes. Typically, distribution planning engineers will examine the entire distribution grid to identify the significant upgrades of greatest priority. PG&E does this using the tools, such as a Load Forecasting Tool, described in its Distribution Resource Plan. In addition, utilities typically asses the projects identified through the planning process with a Risk Assessment Tool. This is used to determine how any one individual project stacks up against other identified projects, from a probability of risk and cost standpoint. The Asset Management Group will then present the list of prioritized projects to management for

[6] "Distribution Planning and Investment and Distributed Generation". PG&E 2014 General Rate Case Appendix C. Section D, "Distribution Capacity Planning and DG", pages C-9 to C-14.

selection to be included in the capital budgets approval process. PG&E uses exactly these processes, and describes them on GRC pages 13-4 and 13-5; PG&E's Risk Informed Budget Allocation process is described on GRC pages 13-11 through 13-14. However, I do not believe the upgrades proposed for the DERIC Program were selected using these processes.

Q. WHY DO YOU BELIEVE STANDARD DISTRIBUTION PLANNING PRACTICES AND RISK ANALYSIS PROCESSES WERE NOT USED TO SELECT THESE DERIC UPGRADES?

A. In discovery TURN requested, for table 13-4, "all workpapers and calculations to support this table." (Table 13-4 presents the 3-year costs for all 7 categories of upgrades proposed for the DERIC Program.) PG&E did not reply with any detail or analysis for substation protective device upgrades or substation capacity upgrades; for reconductoring upgrades, it responded with a few explanatory sentences and some bullet points, with no details or analyses specific to any recommended circuit or upgrade.[7] Had standard distribution planning practices and processes, along with analysis using current risk assessment tools, been used to determine the need for specific upgrades on specific circuits, such detail and analyses would have been readily available. In my experience, the lack of available detail suggests that these specific projects would have failed the test of standard risk analysis, compared to other capital budget items.

[7] PG&E response to DR_TURN_035-Q11

Q. WHAT IS THE IMPLICATION OF NOT UTILIZING STANDARD DISTRIBUTION PLANNING PRACTICES AND PROCESS, ALONG WITH RISK ANALASIS, ON CIRCUITS SELECTED FOR UPGRADE?

A. The implication of not applying common distribution capacity planning processes and risk analysis, is that PG&E's proposed DERIC investments may not be necessary to address system needs.

There is circuit-specific evidence that the reliability and safety issues PG&E predicts from high-DER circuits have not materialized on circuits that already have high DER capacity. To me, this is an indication that PG&E's existing capacity planning practices and processes, as well as risk analysis processes, are working well, and that presumptive DERIC investments are not necessary. This, combined with the fact that retail DER interconnection approval times have fallen from 15 business days in 2012 to 3 business days in 2015, despite a quadrupling of interconnection request volume,[8] is further proof that the DERIC upgrade requests are premature.

The Wired Group compiled Table 1 below from data provided by PG&E in discovery. The data indicates that many of the substations and circuits chosen for significant upgrades in the DERIC Program proposal already exceed PG&E's definition of "High Penetrations of DG". In fact, some substations and circuits chosen already exceed PG&E's definition by significant amounts. (Note that the threshold set by PG&E for taking action in DERIC is 15% of DG capacity as a percentage of peak load, representing

[8] PG&E response to DR_TURN_098-Q02, Attachment 01.

DER interconnect application screen "M" in Rule 21.) *Yet, these circuits have exhibited none of the reliability or safety problems of which PG&E warns in its proposal*. Detailed peak demand and DER capacity data, both current and forecast, on the circuits selected for Reconductoring, Substation Capacity, and Substation Protection upgrades is available in Appendices C, D, and E, respectively.

Table 2: Reliability or safety issues reported to date on circuits/substations selected for significant upgrades[9]

Upgrade category	No. of circuits/subs to be upgraded per DERIC Program proposal	No. of circuits/subs which already exceed high* DER capacity	Reliability or safety issues reported on circuits/subs w/high* DER capacity	Retail DER interconnection delays to date on circuits/subs with high* DER capacity
Reconductoring	12	8[1]	None	None
Substation Capacity	5	5[2]	None	None
Substation Protection	22	13[3]	None	None

* DER capacity (all types) as of 12-31-15 in excess of 15% of 2015 peak demand
[1] One circuit (42891101) has almost 3x the definition of high DER capacity at 43.4%
[2] One substation has almost 10x the definition of high DER capacity at 146.5%
[3] One circuit (252941106) has more than 2x the definition of high DER capacity at 33.6%

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW TRADITIONAL DISTRIBUTION PLANNING APPROACHES CAN BE USED TO INTEGRATE DG?

[9] See Appendices C, D, and E for data to support this table and citations to data sources.

A. Yes. Appendix C of Phase 2 of PG&E's 2014 GRC, entitled "Distribution Planning and Investment and Distributed Generation",[10] provides a perfect example. Consider this quote from sect D. 2. b. "How PG&E's Load Forecast Incorporates DG":

> "Over 99 percent of the DG systems interconnected to PG&E's distribution system are accounted for in the historical peak demands the Company uses to forecast future load. This is because PG&E makes no adjustments to its load forecasting process for small DG systems 8 (i.e., less than 100 kW) which represents nearly all the DG interconnected to the distribution system. In effect, PG&E records the peak load that substation transformers and circuits serve (or "see"). Since substation transformer loads reflect the amount of DG that is interconnected and operating on the peak day, the recorded peak load includes the influence that DG has on the load that the distribution system serves (which is not necessarily the full capacity value of the DG system). Since the load forecast is based on historical peaks, and the historical peaks reflect the contribution that DG makes to the amount of load the system serves, DG is incorporated into the load forecast in terms of both quantity and trend. (Seven years of historical data form the trend, so if DG is growing in a particular area, then that growth is captured to at-least some extent in the forecast.) However, the fact that DG is incorporated in the load forecast does not necessarily mean it is influencing capacity expenditures. What causes capacity expenditures is the relationship of the load forecast relative to available capacity for a specific system component such as a substation transformer, circuit, etc. If there is insufficient capacity (i.e., a deficiency) then a project may be necessary. The ability of DG to influence the capacity expenditure is the confluence of the correct amount and location of DG relative to the deficiency."

This is an excellent description of how to use traditional distribution planning techniques to integrate DG, and it is a method that PG&E is using successfully today to avoid DER integration delays as well as potential reliability and safety issues.

[10] PG&E response to DR_TURN_035-Q04, Attachment 01

Q. WERE YOU ABLE TO DETERMINE HOW PG&E IDENTIFIED THE SUBSTATIONS AND CIRCUITS THAT WERE PROPOSED FOR UPGRADE IN ITS DERIC PROGRAM?

A. PG&E's Distribution Resource Plan Section 2. b., "Integration Capacity Analysis", describes the process that PG&E is proposing to use for DER integration.[11] In discovery, when TURN asked for copies of detailed analyses for picking the identified substations and circuits, PG&E was not able to supply such analysis.[12]

Several of the issues addressed in the DERIC program are associated with "voltage anomalies". However, even if PG&E had used the process described in the "Distribution Resource Plan" they would not have been able to find these voltage problems. The following is a quote from that process section 2. b. i. 3. "Voltage/Power Quality Criteria":

> "PG&E's initial Integration Capacity Analysis cannot directly evaluate all the criteria and subcriteria of voltage / power quality. Currently, only voltage flicker can be assessed."

Voltage flicker is the occurrence of a very short duration of voltage variation, which was not addressed by any of the DERIC solutions. It is apparent that PG&E did not use any of these processes to identify the substations and circuits in its DERIC Program. It appears that the only process that was used was to pick substations and circuits with forecast DER capacity connected by 2020 in excess of 15% of the 2015 peak load on that substation or circuit. Late in the discovery process, PG&E provided a response to DR 94-Q01 that included a method for calculating "Voltage Capacity Limits". However, there is no

[11] PG&E Electric Distribution Resources Plan. Submitted July 1, 2015 in R14-08-013. Pages 22-61.

[12] PG&E response to DR_TURN_035-Q11 and follow-up requests specific to each DERIC upgrade.

indication or evidence that the method was actually used to identify the substations and circuits selected for upgrades in the DERIC Program.

Q. PLEASE DESCRIBE THE OPERATING PRACTICES AND PROCESSES PG&E ALREADY EMPLOYS TO ADDRESS LOCAL VOLTAGE REGULATION OR PROTECTIVE DEVICE UPGRADES AS THEY ARISE.

A. All utilities find it necessary to respond to changes in customer loads on their distribution system on a regular basis. PG&E describes these efforts on page 14-5 of its testimony, including Voltage Complaint Investigation, Troublemen Field Work, and Field Work Plans. Operating practices and processes are quite different from distribution planning, which looks ahead; rather, operating practices and processes generally respond to issues and problems on local distribution circuits as they arise. Solutions are typically identified and implemented within a few days or weeks, rather than the months required for significant upgrades. Solutions such as the capacitor, voltage regulation, and line protection device upgrades proposed in the DERIC Program can and should be dealt with using these standard utility industry approaches, as PG&E has apparently been using to date with good success.

Today, PG&E employs these operating practices to respond to voltage and line protection issues as they arise, whether those issues result from changes in customer loads or from growth in DER, with no apparent reliability or safety problems or delays in retail DER interconnection requests. In fact, until the DER capacity on a circuit reaches 15% of its peak demand, PG&E approves retail DER interconnection requests in technical compliance with its interconnection standards with no examination into distribution system impact.[13] Further, the 15% of peak demand guideline is arbitrary and does not mandate any specific upgrades; it is a screening device only. It is meant to trigger potential investigations, but will not necessarily result in investigations, upgrades, or retail DER integration delays. So it is difficult for me to understand why the proposed DERIC Program upgrades are required to avoid future retail DER integration delays.

Q. WHAT DOES THIS HAVE TO DO WITH PG&E'S DERIC PROGRAM PROPOSAL?

A. PG&E's DERIC Program proposes investing over $11 million to upgrade capacitor banks, and $23.5 million to upgrade other voltage regulating devices, from 2017-2019. The proposal also calls for $11 million to upgrade line protection devices. All of these upgrades would normally be undertaken locally on an "as needed" basis in the course of normal operations. Presumptive upgrades of these devices on the notion that they might be needed some day is simply not consistent with standard utility practices and represents a questionable value proposition for ratepayers.

Q. DO YOU HAVE ANY DATA TO SUPPORT THE NOTION THAT PRESUMPTIVE INVESTMENT OF DEVICES THAT WOULD OTHERWISE BE

[13] "Initial Review Process for Applications to Interconnect Generating Facilities". Rule 21. Accessed via Internet on PG&E website from page "Distribution Interconnection Handbook" at http://www.pge.com/en/mybusiness/services/nonpge/generateownpower/distributedgeneration/interconnectionhandbook/index.page

ADDRESSED ON AN "AS NEEDED" BASIS IN THE COURSE OF NORMAL OPERATIONS ARE OF QUESTIONABLE VALUE?

A. Yes. The Wired Group compiled the table below from data provided by PG&E in discovery. The data indicates that many of the circuits chosen for local upgrades in the DERIC Program proposal meet PG&E's definition of "high penetrations of DG", yet have exhibited none of the reliability or safety problems of which PG&E warns in its DERIC proposal.

Table 2: Reliability or safety issues reported to date on circuits/substations selected for local upgrades[14]

Upgrade Category	No. of Circuits to be upgraded by 2020	No. of Circuits with high* DER capacity as of 12-31-15	Reliability or safety issues reported on circuits with high* DER capacity	Retail DER Interconnection delays to date on circuits with high* DER capacity
Capacitor Banks	348	177[1]	None	None
Voltage Regulating Devices	92	55[1]	None	None
Line Protection Devices	252	157[2]	None	None

* DER capacity (all types) as of 12-31-15 in excess of 15% of 2015 peak demand
[1] One circuit (103491102) had more than 7x the definition of high DER capacity at 98.9%
[2] One circuit (62021101) had more than 8x the definition of high DER capacity at 120.9%

Q. HOW CAN YOU BE CERTAIN EXISTING PRACTICES AND PROCESSES WILL BE SUFFICIENT TO AVOID RETAIL DER INTEGRATION DELAYS, AS

[14] PG&E response to DR_TURN_094-Q02, Attachment 01CONF.

WELL AS RELIABILITY OR SAFETY ISSUES, AS DER CAPACITY CONTINUES TO INCREASE?

A. Of course I cannot be certain there will never be a DER integration delay or DER-related customer voltage complaint. However by looking at 2020 DER capacity forecasts by circuit, and comparing the level of DER capacity currently being managed without reliability or safety problems or DER integration delays, one can get comfortable with the notion that existing PG&E practices and processes, be they distribution planning or operational in nature, can deal effectively with increasing DER capacity. The Wired Group compiled Table 3 below from data provided by PG&E in discovery. The data indicates that presumed DERIC Program upgrades are premature.

Table 3: Number of circuits and substations selected for DERIC upgrades with DER capacity in 2020 that is below the greatest levels being successfully managed today[15]

Upgrade Category	Number of Circuits/Subs to be upgraded by 2020	Greatest DER capacity as % of peak kW being successfully managed today (no reliability or safety incidents or retail DER integration delays)	Number of circuits/subs in 2020 (per PG&E DER forecast) below the greatest DER capacity % being successfully managed today*
Reconductoring	12	43.4%	[redacted]
Substation Capacity	5	146.5%	[redacted]
Substation Protection	22	33.6%	[redacted]
Capacitor Banks	348	111.0%	[redacted]
Voltage Regulating Devices	92	98.9%	[redacted]
Line Protection Devices	252	120.9%	[redacted]

* Conservatively calculated at 2020 DER capacity forecast as a percent of 2015 peak kW.

This table summarizes data found in Appendices C through H. Using Appendix C, "Reconductoring Circuit Data Detail" as an example, I will illustrate how the data for each of the upgrades indicates that presumptive DERIC investments are premature.

Examining the data in the table in Appendix C, we can see that for circuit 42891101, the "Current DG % of Peak kW" (the 5th column) is 43%. This circuit had the highest percentage of DG as compared to its peak load of all of the circuits identified for reconductoring. Note that the threshold set by PG&E for taking action in DERIC is 15% DG capacity as a percentage of peak load, representing DER interconnect application

[15] PG&E response to DR_TURN_094-Q02, Attachment 01CONF

screen "M" in Rule 21. Despite the fact that current DG percent of peak kW on circuit 42891101 is almost 3 times the PG&E threshold for DERIC upgrades, PG&E reports no reliability or safety issues to date, nor any retail DER integration delays. The last column of the table indicates that [redacted] of the 12 circuits selected for reconductoring in DERIC will not have DG capacity greater than that already experienced without incident on circuit 42891101, even by 2020. Yet, PG&E's DERIC Program insists all 12 reconductoring project should be completed now. It could be many years before the DER capacity achieves a level that would require the reconductoring proposed by PG&E, leading to my conclusion that these upgrades are being proposed far in advance of the time they will actually be required. The same approach can be applied to the other upgrades described in Table 3 above, using Appendices D through H as detail to point out the inconsistencies in PG&E's DERIC Program logic.

Q. SO YOU DO NOT AGREE THAT PG&E SHOULD TAKE PRESUMPTIVE ACTION WHEN DG CAPACITY REACHES 15% OF PEAK LOAD?

A. No, I do not, for two reasons. First, the 15% level is completely arbitrary. There is no research or guideline that suggests grid owners must take presumptive action to prepare for any particular level of DER. The answer is "it depends" on a number of factors: line impedance, the location and characteristics of loads on the line, the location and characteristics of the DER on the line, local circuit design and links with nearby circuits, and others. This is precisely why properly administered, flexible, "as needed" approaches to grid planning and operations – proactively in the case of significant upgrades, and reactively in the case of local upgrades – are well-suited, and perfectly appropriate for, managing increasing levels of DERs.

Second, as I have stated throughout my testimony, I feel that most if not all proposed DERIC Program upgrades would not pass any kind of legitimate Risk Analysis at this time. At some point, as the levels of DERs grow ever-larger, voltage problems and other types of concerns will probably appear, even though none have appeared to date despite some fairly significant DER levels. Any such problems will be minor and infrequent to start, at which point PG&E will begin to gather data. Soon after, there will be enough information for more rigorous incorporation into a proper risk analysis. When the results of such risk analyses warrant action, PG&E should and will take action. With experience and a proper risk analysis in place, PG&E will know the conditions to look for and the type of action best-suited to address anticipated issues in the most cost-effective manner possible. This is a much more pragmatic approach than making presumptive investments to address potential or hypothetical problems that may not materialize, or for which timing is highly variable.

Q. YOUR TESTIMONY HAS YET TO ADDRESS THE DERIC PROPOSAL TO INSTALL RELAYS IN SUBSTATIONS WITH SINGLE-PHASE FUSES ON THE HIGH-VOLTAGE SIDE OF TRANSFORMERS.

A. This issue illustrates a problem that is somewhat common among distribution engineers: a desire for perfection. Much like cybersecurity experts who test system security by identifying and exploiting any and every possible weakness, electrical engineers have been trained to spot and eliminate avoidable problems, no matter how unlikely the probability of occurrence. Distribution engineers have been known to develop solutions at costs that are far out of proportion to the probability an issue they've determined could occur, actually will occur. I believe this solution is an example of one of those instances.

In discovery, TURN verified the chain of events that would need to occur for the problem to be solved by installing relays would actually manifest, and asked PG&E to estimate the probability of each. The individual and collective probabilities PG&E provided are presented in Table 4 below,[16] while I added my own estimates based on my experience.

Table 4: *Probability that the alleged problem to be solved by installing relays in substations with single-phase fuses on the high-voltage side of transformers will occur*

Link in the Chain of Events Required to Create the Problem	Probability as characterized by PG&E	Probability per witness Stephens' experience
[redacted]	[redacted]	0.006[17]
[redacted]	[redacted]	1.000
[redacted]	[redacted]	0.500
[redacted]	[redacted]	0.010
[redacted]	[redacted]	0.100
[redacted]	[redacted]	0.000003 (probabilities multiplied)

[16] PG&E response to DR_TURN_094-Q13CONF

[17] Woodcock, David J. *Assessing Health and Criticality of Substation Transformers*. Electric Energy T&D Magazine. Volume 9, No. 3. Pages 27-30.

To summarize, the problem PG&E describes has 1 chance in 333,000 of occurring. I do not believe the probability this problem will occur warrants the $2.3 million investment required to prevent it. And I certainly do not believe the issue identified and proposed solution would pass any type of Risk Analysis Assessment.

Q. ARE THERE OTHER SITUATIONS LIKE THIS IN THE DERIC PROGRAM PROPOSAL?

A. Yes, PG&E describes one other "problem" that is similar for its low probability of occurrence. But this "problem" is also characterized by potential impact to only a very small numbers of customers, as well as relatively minor associated consequences.

One of the idiosyncrasies of some voltage regulation schemes in place in PG&E's distribution grid is the use of open-delta configuration for voltage regulation. The open-delta configuration uses just two of the three phases to accomplish three phase voltage regulation. PG&E claims that under a certain combination of circumstances, high levels of DER on a circuit equipped with open-delta configuration voltage regulation could cause machine-based generators owned by a small minority of customers to trip (shut down). PG&E calls this situation "Nuisance Tripping". While I believe PG&E's claim to be technically accurate, I think the probability of occurrence to be extremely low, as PG&E has not been able to document a single incidence of it on the Company's grid.

In addition, the consequences associated in the event the problem occurs are small. The "Nuisance Tripping" would be a result of the voltage fluctuations on the distribution line. These fluctuations would cause the generator to drop off line when the voltage on the circuit moved out of its required range, as required by IEEE 1547. These trips off line would result in a normal shut down of the generator, should not result in any safety hazards, and are therefore of low consequence. (Such generators can simply be restarted once voltage fluctuations pass.) Low probability of occurrence, combined with the small number of customers who would be affected, and the low consequences associated in the event the problem occurs, make this another problem not worth spending ratepayer funds to prevent. And once again I do not believe this would pass any type of Risk Analysis Assessment.

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. As a summary comment, several of the potential issues PG&E describes in its DERIC Program proposal relate to damage to machine-based DER, or inconvenience to customers which own machine-based DER. There are likely to be only a small number of customers who own machine-based generators, such as microturbines powered by waste gas or industrial process waste heat. Machine-based generators are generally much larger and much more costly to install than rooftop PV solar systems, thus they are found in dramatically smaller numbers on most distribution grids.

Not only are these customers a small minority of all customers, ratepayers are not responsible for the protection of such equipment or for the inconvenience of such customers. Rule 21 clearly requires that customers install equipment that disconnects publicly-owned DERs from the distribution grid in the presence of high voltage. Rule 21 also requires that the facility grounding schemes of customer-owned DER shall not disrupt the coordination of the distribution grid protection scheme. If these rules are strictly adhered to and enforced, even as growth in DER may require changes to equipment installed by DER-owning customers, many of the problems that the DERIC Program proposal attempts to solve at ratepayer cost would not materialize.

IV. THE DERIC PROGRAM WILL NEEDLESSLY INCREASE RATES (ALVAREZ)

Q. WHY DO YOU BELIEVE THE DERIC PROGRAM WILL NEEDLESSLY INCREASE RATES?

A. There are actually several reasons I will cover in the testimony immediately following:

- The DERIC Program is vastly more expensive for ratepayers than the "as needed" approaches used successfully to date;
- The DERIC Program will subsidize wholesale DER owners at ratepayer expense;
- PG&E has already attempted to subsidize wholesale DER owners at ratepayer expense;
- The presumptive DER integration investments proposed in DERIC transfers PG&E performance risk into economic risk for ratepayers.

Q. PLEASE SUPPORT YOUR CLAIM THAT THE DERIC PROGRAM IS VASTLY MORE EXPENSIVE FOR RATEPAYERS THAN THE "AS NEEDED" APPROACHES USED SUCCESSFULLY TO DATE.

A. Certainly. Using PG&E's advice letter 4660-E, and data obtained in discovery, we calculated the average cost of grid upgrades PG&E has incurred to integrate almost 600 MW of retail DER on a "per kW" basis using the traditional, "as needed" approaches described and advocated by Mr. Stephens in his testimony.[18] We calculated an average grid upgrade cost to integrate retail DER using traditional, as needed approaches of $9.45 per kW of DER integrated.

Table 5: Historical cost of integrating retail DER using traditional, "as needed" approaches

Line	Description, 11-1-13 to 5-31-15	Amount	Data Source
A	Distribution Engineering Costs to integrate retail DER	$2,128,980	Advice letter 4660-E, Table 2
B	Facility Upgrade Costs to integrate retail	3,513,511	Advice letter 4660-E, Table 4
C	Total cost to upgrade grid to integrate retail DER	$5,642,491	A + B
D	Capacity (kW) of retail DER kW integrated	597,000	PG&E Response to DR TURN_073_Q03
	Grid upgrade cost per kW to integrate DER 11-1-13 to 5-31-15:	$9.45	C ÷ D

Q. HOW DOES THIS AVERAGE HISTORICAL RETAIL DER INTEGRATION COST PER KW COMPARE TO THE COST OF THE DERIC PROPOSAL?

[18] PG&E response to DR_TURN_073_Q03

A. It's somewhat difficult to say. In discovery, PG&E would not commit to the amount of additional retail DER capacity the Company could reliably and safely integrate if the presumptive grid investments recommended in the DERIC Program proposal were made. For this reason it is difficult to determine the benefit DERIC Program spending is intended to deliver if approved. However, we can assume a worst-case scenario as one indication.

As a conservative assumption, we assumed the retail DER capacity growth forecast PG&E provided by 2020 is the maximum amount that could be integrated for the proposed DERIC Program investment. This may be an overly conservative assumption, but it provides a starting point for comparison. Using DERIC Program cost data from GRC table 13-4, and 2020 retail DER forecast data provided by PG&E in discovery,[19] we calculated the cost of the DERIC Program to be $[redacted] per kW of retail DER capacity integrated.

Table 6: Cost of integrating DER using the presumptive DERIC approach, worst case scenario

Line	Description	Amount	Data Source
A	DERIC Program proposed investment	$99,762,000	Table 13-4, GRC page 13-35
B	Retail DER increase 12-31-15 to 12-31-19 (in kW)	[redacted]	PG&E Response to DR TURN_094_Q02Atch01CONF
	DERIC Program cost per kW of retail capacity integrated (forecast = max)	[redacted]	A ÷ B

[19] PG&E Response to DR_TURN_094-Q02, Attachment 01CONF

While the amount of additional retail DER capacity the proposed DERIC Program could reliably and safely integrate is likely greater than the forecast DER capacity growth, *the DERIC Program would need to integrate more than* [redacted] *times the forecast growth to be as cost-effective as the traditional, as-needed approaches utilized to date.*

Q. DO YOU HAVE ANY THOUGHTS AS TO WHY THE COST OF PRESUMPTIVE INVESTMENT IS SO MUCH HIGHER THAN THE COST OF TRADITIONAL, "AS NEEDED" APROACHES?

A. As described in Mr. Stephens' testimony, presumptive action may result in investment that is not needed, or investment far in advance of the time needed. This is certainly a key contributor to the out-sized cost of the DERIC Program per kW of DER relative to "as needed" approaches. But I know of at least one specific example that is highly illustrative.

In discovery, PG&E estimated that the cost to replace a single voltage regulator is $100,000.[20] PG&E claims such replacement is required to ensure voltage regulators operate properly in the presence of two-way power flow associated with high levels of DER. While Mr. Stephens and I believe this cost estimate to be a bit on the high side, more troubling is the proposal to replace voltage regulators at all. Voltage regulator retrofit kits are available which allow utilities to simply replace the controller module of existing voltage regulators with more advanced controllers able to accommodate two-way power flow. In addition, these advanced controllers are available with communications capabilities that enable SCADA system integration. Advanced controllers cost around

[20] PG&E response to DR_TURN_095-Q02

$2,000, with an installed cost (including all engineering, labor, and commissioning) of about $5,000 per voltage regulator. The fact that PG&E is proposing a $100,000 solution when a $5,000 solution is available is yet another indication that PG&E's DERIC Program proposes investments that are not only unnecessary, but also unreasonable.

Q. WHILE YOUR POINTS ABOUT THE COST OF PRESUMPTIVE INVESTMENT ARE WELL TAKEN, HOW DO YOU RESPOND TO THOSE WHO FEEL THE COST IS WORTH AVOIDING A HAWAII SITUATION?

A. By "a Hawaii situation", I assume you are referring to the idea that failure to sufficiently prepare the distribution grid for increases in DER is now resulting in delays in DER integration in Hawaii. I do not know enough about the specifics of Hawaiian utility preparations to render an opinion on the sufficiency of any such efforts. In addition, as I think Mr, Stephens' testimony makes clear, "as needed" investment may be sufficient to avoid "a Hawaii situation". However, I can tell you with confidence that the level of DER being integrated right now in Hawaii is far beyond what PG&E will experience by 2020, according to PG&E's overall DER growth forecasts.

I prepared Table 7 below from data reported by the Hawaii State Energy Office[21] and a variety of reputable sources as noted below the table. Despite aggressive DER growth forecasts for DERIC substations/circuits ([redacted]),[22] which I then

[21] *Hawaii Energy Facts and Figures*. Hawaii State Energy Office. May, 2015. Pages 2 (system peak) and 18 (installed PV solar capacity).

[22] PG&E response to DR_TURN_094-Q02, Attachment 01CONF, duplicate circuits removed.

applied to all the DER in PG&E's entire service territory (unlikely), the table indicates just how far behind DER integration at PG&E is today compared to Hawaii, and how far behind PG&E still will be by 2020. (Note that differences in "percent of peak" from PG&E's NEM reports is due to PG&E's use of aggregate non-coincident peaks in those reports; coincident system peak is used in Table 7 for consistency with available Hawaii data.)

Table 7: Relative DER capacity comparisons, selected Hawaiian islands' 2014 actuals vs. PG&E service area, 2014 actual and 2020 forecast

Geography/IOU	Year	Coincident System Peak (MW)	DER Capacity (MW)	DER Capacity as % of Coincident System Peak
Hawaii/HELCO	2014	189.0	54.7	28.9%
Maui/MECO	2014	199.0	56.9	28.6%
CA/PG&E	2014	17,638.0[a]	2,002.0[b]	11.4%
CA/PG&E	2020	18,946.6[c]	[redacted][d]	[redacted]%

Notes:
[a] From PG&E's 2014 submission to US DOE on EIA Form 861, Worksheet 2A, Section 6
[b] From PG&E's July 1, 2015 DRP: 1700 MW retail, page 95; 302 MW wholesale, page 98
[c] Calculated at 1.2% compound annual growth rate per CEC demand forecast update, PG&E Planning Area, mid-case, December 2014, page 22.
[d] [redacted] growth rate on DERIC subs/circuits per PG&E response to DR_TURN_094-Q02Atch01CONF, duplicate circuits removed, applied to all DER from PG&E's DRP

Q. WHY DO YOU BELIEVE THE DERIC PROGRAM SUBSIDIZES WHOLESALE DER OWNERS AT RATEPAYERS' EXPENSE?

A. In its DERIC Program proposal PG&E cites many reliability and safety problems it claims will be caused by high levels of DER, including complications associated with two-way power flow. However, these reliability and safety problems, to the extent they might occur, cannot be attributed solely to retail DER. High levels of wholesale DER would contribute to the exact same problems PG&E claims will be caused by retail DER. In fact, wholesale DER may contribute more than its share of these claimed problems relative to retail, as prospective wholesale DER owners may prefer to locate large PV solar systems in sparsely populated areas with lower real estate costs. These locations typically have low native loads, creating a situation more likely to create two-way power flow and any associated problems that might occur. Retail, NEM-eligible systems are, by definition, located where there is load. They are sized so as not to exceed average annual on-site load. The DERIC Program proposes investments that will prepare the grid for future wholesale DER as well as future retail DER,[23] enabling future wholesale DER owners to avoid paying their fair shares of grid upgrade costs.

Q. AND YOU BELIEVE SUCH SUBSIDIES HAVE ALREADY OCCURRED?

A. Yes. The DERIC Program includes $19.4 million – plus escalation – to upgrade 5 substations. In both the DERIC Program proposal and subsequent discovery, PG&E makes clear the proposed spending is intended to accommodate retail DER only. Data secured from PG&E in discovery clearly indicates any requirement to upgrade these 5 substations was caused by wholesale DER, not retail DER. As shown in Table 8 below, wholesale DER comprised 95.1% to 99.9% of all the distributed generation connected to the 5 circuit banks PG&E is proposing to add to or upgrade.[24] PG&E should have

[23] PG&E responses to DR_TURN_098-Q04 and Q05.

[24] PG&E response to DR_TURN_073-Q02, Attachment 02

charged the costs of these upgrades to wholesale DER owners. It is TURN's position that PG&E must now complete these upgrades at shareholder expense.

Table 8: Percent of wholesale Der on the banks of 5 substations selected for upgrades

Sub	12-31-15 DER kW (total)	12-31-19 DER kW (forecast)	12-31-15 Wholesale DER kW	Wholesale DER % of Total DER 12-31-15	Wholesale DER* % of 2020 Forecast DER
A	30,500	32,802	30,000	98.4%	91.5%
B	20,184	21,507	20,000	99.1%	93.0%
C	20,928	21,248	20,000	95.6%	94.1%
D	21,036	22,940	20,000	95.1%	87.2%
E	10,008	23,316	19,000	99.9%	81.5%

*Assumes zero new wholesale DER capacity will be added after 12-31-15

Q. WHAT DO YOU BELIEVE SHOULD BE DONE ABOUT WHOLESALE DER SUBSIDIES?

A. I believe some sort of financial mechanism is needed to allocate the cost of grid upgrades, to the extent they are necessary, between both retail DER and wholesale DER. A wholesale DER owner should be responsible for the cost of the upgrades immediately necessary to integrate his or her DER project per Rule 21. But wholesale DER owners should also be responsible for the cost of any overall preparations made historically, or that might be required in the future, to reliably and safely deliver their products to markets. A recognition that wholesale DER owners' use of the grid creates ongoing costs, as well as ongoing value, for which wholesale DER owners must pay, is critical to avoiding ratepayer subsidies. A manufacturer of widgets would never assume his products would somehow arrive at customers' doorsteps without arranging for, and paying, a shipping company to deliver them. Both parties know that one of them must pay the shipping company for its services, and neither party could imagine a scenario where the shipping company's other customers would pay to ship the widgets. Yet, unless wholesale DER owners are charged for the full cost of the value delivered by PG&E's distribution grid, ratepayers will subsidize wholesale DER integration costs in precisely this manner. I believe it is appropriate and important to address how wholesale DER owners should be charged for ongoing services and value provided by the grid in the Distribution Resource Planning proceeding and/or the Rule 21 proceeding.

Q. WHY IS IT IN PG&E'S ECONOMIC INTEREST TO SUBSIDIZE WHOLESALE DER?

A. When faced with a choice between passing the cost of multi-million dollar upgrades to wholesalers with no mark-up per Rule 21 and PG&E's wholesale distribution tariff, or adding those costs to rate base, PG&E has a financial incentive to choose the latter approach. These assets have useful lives of 20 years or more and will thus earn significant shareholder profits. PG&E's use of DERIC to subsidize wholesale DER integration costs with ratepayer funds is further evidence that the DERIC Program represents an unjust ratepayer impact.

Q. ARE THERE ANY OTHER ISSUES ASSOCIATED WITH PRESUMPTIVE INVESTMENT AT STAKE IN PG&E'S DERIC PROGRAM PROPOSAL?

A. Yes, I believe there is one additional issue. In addition to making investments that may not be needed, or not be needed for several years or more, and are unjust as a result of ratepayer subsidy of wholesale DER owners, the presumptive nature of PG&E's

recommended DERIC Program investments transfers PG&E's performance risk into ratepayer economic risk.

As I testified earlier (Section II) in this testimony, PG&E retains the responsibility for addressing technical and business issues as they arise at the least cost to ratepayers. Mr. Stephens indicated in his testimony that PG&E has successfully been managing this responsibility as it relates to the growth in DER through existing distribution planning and grid operations practices and processes. The reliable and safe integration of growing DER using existing practices and processes represents performance risk that PG&E must manage.

By making the presumptive investments proposed in the DERIC program, PG&E reduces its performance risk. If all upgrades are made far in advance of the time in which they are needed, PG&E no longer need worry about identifying upgrades as the need for them arises. Presumptive investment also allows PG&E to use rate-based, capital-intensive solutions rather than low-cost operating expense solutions. (Consider the capital cost of upgrading a capacitor bank to the incremental operating cost of dispatching a lineman to change the setting on a fixed capacitor bank.) Presumptive investment obviously takes some pressure off of PG&E distribution grid managers. But as demonstrated earlier in my testimony, this reduction in PG&E performance risk comes at a dramatic increase in economic cost (and risk) to ratepayers. I do not believe PG&E should be allowed to transfer its performance risk into ratepayer economic risk.

V. THE DERIC PROPOSAL FAILS TO PROVIDE NET BENEFITS TO RATEPAYERS (ALVAREZ)

Q. WHY DO YOU BELIEVE THE DERIC PROPOSAL FAILS TO PROVIDE NET BENEFITS?

A. There are several reasons why the DERIC Program proposal fails to provide net benefits. For a net benefit test to be favorable from a ratepayer perspective, several conditions must apply:

- The benefits must accrue to ratepayers and result from the proposed investment.
- The size of the benefits and the size of the costs must be known.
- The incremental costs must be reasonable in relation to the incremental benefits.
- There must be no less-expensive method available to secure the anticipated benefits.

Allow me to review, from the testimony presented by Mr. Stephens or myself, how the DERIC Program proposal fails on all of these counts.

As Mr. Stephens' testimony indicates, the presumptive investments proposed in DERIC are not needed to avoid delays in retail DER integration. Not only have PG&E's existing practices and processes managed to avoid delays in retail DER integration, they have avoided the reliability and safety issues PG&E claims will arise despite multiple instances of high DER penetration that already exist in portions of PG&E's service territory. If there are any benefits from DERIC, my testimony indicates they accrue disproportionately to wholesale DER owners, not ratepayers. To summarize, it is not at all clear that ratepayers will receive benefits from the proposed investment.

In discovery, as indicated in my testimony above, PG&E would not commit to the amount of additional retail DER the Company would be able to integrate if the DERIC Program investments were made. This makes it impossible for ratepayers to estimate the size of the benefit they might receive from DERIC. The failure to make a commitment as to the additional retail DER PG&E would be able to integrate for $99 million also implies that additional costs might be required. Without knowing the size of the DER to be integrated nor the ultimate costs of such integration, it is impossible to even complete a net benefits test, let alone to assume the outcome of the net benefits test will be favorable for ratepayers.

Though Mr. Stephens and I believe ratepayer benefits from the DERIC program to be near zero, there are two technical arguments raised by PG&E that we support. Installing relays on the high-side of transformers in substations with single-phase breakers will indeed help avoid a problem in a certain rare set of circumstances. However the probability the problem will occur is so small, and the likelihood of incremental substation equipment damage so remote, that the cost to solve the problem is far out of proportion to the size of the problem. Similarly, we agree that a certain type of voltage regulation configuration (open delta) might, in rare instances, result in nuisance tripping for generation owned by a small number of customers. But this is more accurately categorized as an inconvenience rather than a problem, and does not impact 99% of ratepayers in any event. DERIC Program costs are simply not reasonable in relation to the incremental benefits to ratepayers.

And finally, there must be no less-expensive method available to secure the benefits claimed. To repeat, the low-cost solutions successfully employed today represent one less-expensive method to integrate increasing levels of DER. But there are other solutions that might be less expensive than DERIC, like DER management systems; retrofitting rather than replacing voltage regulators; increased use of smart inverters or electric storage; and pricing signals based on an approach to Locational Net Benefit Analysis that fully incorporates DER integration costs. Tests and demonstration projects utilizing these solutions have either not yet been completed or not yet started, so ratepayers cannot be assured they are getting solutions at the lowest possible costs. PG&E should be required to run risk analyses on all of these proposals and provide their risk assumptions and their risk analysis results as compared to other capital expenditure risk analysis.

Q. DO YOU HAVE ANY ADDITIONAL DATA THAT CALLS INTO QUESTION THE LEGITIMACY OF THE DERIC PROPOSAL?

A. While the DERIC Program is relatively small, the Commission should consider the fact that PG&Es' distribution investments have been larger historically than those of other IOUs in the United States. Using publicly-available data provided by PG&E and other US IOUs in FERC Form 1 filings and EIA Form 861 filings, I have determined that PG&E's distribution assets are 29% higher per customer than the average of all US IOUs ($4,525 vs. $3,500 as of December 31, 2014; n = 126).

There are a few factors that influence the level of assets required to distribute electricity reliably and safely. Two of the more relevant factors for comparison purposes would be peak demand and customer density. PG&E's peak demand per customer (3.7 kW) is only 65% of the average of all US IOUs (5.7 kW; n = 131). (I believe low peak demand per customer in PG&E's service territory may be the result of lower air conditioning penetration and/or less heavy industry relative to other geographies served by U.S. IOUs.) In addition, PG&E's customer density is average (37.8 customers per distribution line mile compared to the US IOU average of 38.0; n = 105). These factors do not, therefore, support PG&E's 29% higher asset quantity.

I also found that PG&E's distribution assets are growing faster than the average rate of US IOUs. From December 31, 2010 to December 31, 2014, PG&E distribution assets per customer grew 25%, while the average for US IOUs for this time period was only 17% (n = 126). Growth in peak demand does not fully explain distribution asset growth, as PG&E's peak demand per customer has only grown from 3.3 kW to 3.7 kW (12%) over this time frame. All of these statistics indicate that PG&E has been spending more distribution capital than other major IOUs, even though its peak load is lower than average. This data is presented in chart form for convenient visualization in Appendix I.

Of course, PG&E has justified some of its spending based on the need to replace "aging infrastructure." I have not had the opportunity to fully evaluate the validity of this claim, but note that almost every US IOU is currently making this claim. I also note that the growth in distributed solar generation in California has been ongoing for some time, notably with the launch of the California Solar Initiative in 2008. To the extent PG&E

has been replacing distribution capital assets, it should have already been making the investments necessary to enable greater DER penetration. The Commission should evaluate whether PF&E's many investments in Grid Reliability and Grid Automation have taken into account the types of issues being addressed in the DERIC Program, and if not, why not?

VI. CONCLUSIONS AND RECOMMENDATIONS (ALVAREZ)

Q. WHAT ARE YOUR RECOMMENDATIONS IN THIS CASE?

A. I have five recommendations.

1) TURN recommends the Commission reject the DERIC Program in its entirety based on the arguments supported by this testimony, resulting in a 2017 test year capital reduction of $17.07 million in account MWC 06 and $4.165 million in account MWC 46, plus respective escalations. Similarly, TURN recommends that presumptive DERIC Program investments proposed for 2018 and 2019 be prohibited.

2) TURN recommends the Commission order PG&E to promptly complete the 5 substation capacity upgrades made necessary by installed wholesale DER, but not charged to wholesale DER owners, at shareholder expense.

3) TURN recommends PG&E prioritize, and pursue research funds to complete, demonstration projects to find the most pragmatic and cost-effective approaches to

integrating increased DER capacity. These efforts should focus upon, but perhaps not be limited to:

- Distributed Energy Resource Management Systems
- Accelerated adoption of advanced smart inverter standards (per the recommendations of the Smart Inverter Working Group)
- Expanded use of electric storage to reduce incidence of two-way power flow
- Customer applied technologies that better protect machine-based DER and voltage- and phase-sensitive equipment (rather than asking ratepayers to fund more expensive, grid-based approaches to protecting sensitive customer equipment)

4) TURN recommends the Commission initiate a rulemaking, or add to the scope of existing Rule 21 Rulemaking 11-09-011, to consider the level of the responsibility customers who own sensitive equipment have to protect their equipment. If increasing DER is to become the new reality of the distribution grid, customers who own sensitive equipment, such as machine-based DER and 3-phase motors, may need to take new precautions. This is not unlike the responsibility certain customers take on today regarding grid reliability; customers for whom existing reliability is insufficient to meet particular business needs install back-up generation. The Commission has determined that the needs of a few customers to secure higher-than-average reliability is not cause to demand the same reliability overall, or for the associated costs to be socialized to all ratepayers for the benefit of a few. As DER increases, the assumption

that ratepayers bear responsibility for the cost of grid upgrades that might be needed to protect the sensitive equipment owned by a few is not at all clear or justified.

5) Finally, TURN recommends the Commission prioritize the prompt completion of the DRP proceeding to resolve issues raised in this testimony, including:
   - A resolution as to how DER integration costs should be incorporated into Locational Net Benefit Analysis modeling; and
   - A resolution as to how the cost of any grid upgrades made presumptively to accommodate anticipated increases in wholesale DER be socialized to as-yet-unidentified wholesale DER projects; and
   - Defined expectations of California IOUs regarding the incorporation of DER integration into existing distribution planning and operations, incorporation into existing risk analysis methods, and that DER integration be reliably and safely completed at least cost to ratepayers while avoiding subsidies of wholesale DER owners.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDICIES

A. Alvarez Curriculum Vitae

B. Stephens Curriculum Vitae

C. Reconductoring Circuit Data Detail (CONFIDENTIAL)

D. Substation Capacity Data Detail (CONFIDENTIAL)

E. Substation Protective Device Circuit Data Detail (CONFIDENTIAL)

F. Capacitor Bank Circuit Random Sample Data Detail (CONFIDENTIAL)

G. Voltage Regulating Device Circuit Random Sample Data Detail (CONFIDENTIAL)

H. Line Protective Device Circuit Random Sample Data Detail (CONFIDENTIAL)

I. Distribution Assets per Customer Benchmark Data Charts

Notes regarding Appendices C-H

Data for tables in Appendices C-H is sourced from PG&E responses to the TURN data requests listed below.

Column "2015 Rated Capacity" (in kW or KVA as indicated): Circuit capacity in amps (DR_TURN_73-Q02ATCH01) X Circuit Voltage (DR_TURN_94-Q03Atch01) X $\sqrt{3}$

Columns "2015 Peak kW", "Current DG Capacity 12-31-15", and "Forecast DG Capacity 12-31-19": DR_TURN_94-Q02Atch01CONF

Column "2015 Minimum Load at Noon (kW)": PGE_DRP_Profiles_Workbook_20150701.xls available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5139

All forecast columns related to demand growth over time: In all cases, forecast growth in demand was estimated at 1.2% compounded annually from 2015 to 2020. This is consistent with the mid-case estimate for the PG&E Planning Area 2014-2024 developed by the California Energy Commission in its recent California Energy Demand Forecast Update.[25]

[25] Kavalec, Chris. *California Energy Demand Updated Forecast, 2015-2025.* California Energy Commission Staff Draft Report CEC-200-2014-009-SD. December, 2014. Page 22.

Curriculum Vitae -- Paul J. Alvarez MM, NPDP

Wired Group, PO Box 150963, Lakewood, CO 80215 palvarez@wiredgroup.net 720.308.2407

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 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.

APPENDIX A – ALVAREZ CURRICULUM VITAE

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.

APPENDIX B – STEPHENS CURRICULUM VITAE

Curriculum Vitae – Dennis Stephens EE

Wired Group, PO Box 150963, Lakewood, CO 80215 dstephens@wiredgroup.net 303.434.0957

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

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.

APPENDIX C – RECONDUCTORING CIRCUIT DATA DETAIL

CONFIDENTIAL

APPENDIX D – SUBSTATION CAPACITY DATA DETAIL

CONFIDENTIAL

APPENDIX E – SUBSTATION PROTECTIVE DEVICE CIRCUIT DATA DETAIL

CONFIDENTIAL

Note: 20 of 348 circuits identified by PG&E for Capacitor Bank Upgrades were selected at random using a random number generator. Data from the 20 randomly-selected circuits obtained in discovery is presented in the table below.

CONFIDENTIAL

Note: 10 of 93 circuits identified by PG&E for Voltage Regulating Device Upgrades were selected at random using a random number generator. Data from the 10 randomly-selected circuits obtained in discovery is presented in the table below.

CONFIDENTIAL

APPENDIX H – LINE PROTECTIVE DEVICE CIRCUIT SAMPLE DATA DETAIL

Note: 20 of 253 circuits identified by PG&E for Line Protective Device Upgrades were selected at random using a random number generator. Data from the 20 randomly-selected circuits obtained in discovery is presented in the table below.

CONFIDENTIAL

APPENDIX I – DISTRIBUTION ASSETS PER CUSTOMER BENCHMARK CHARTS