BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the General Rate Case Plan for Energy Utilities.	RULEMAKING 13-11-006 (FILED NOVEMBER 14, 2013)

COMMENTS OF SAN DIEGO CONSUMERS' ACTION NETWORK ON ORDER INSTITUTING RULEMAKING TO DEVELOP A RISK-BASED DECISION-MAKING FRAMEWORK TO EVALUATE SAFETY AND RELIABILITY IMPROVEMENTS AND REVISE THE GENERAL RATE CASE PLAN FOR ENERGY UTILITIES

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Pursuant to this OIR, San Diego Consumers' Action Network (SDCAN) submits comments responsive to the scope of issues and questions raised in Sections 4.3 through 4.6 of this November 14, 2013-issued rulemaking. SDCAN's director and its experts have each participated in General Rate Cases for over 30 years. Since 1984, each of the authors of these SDCAN's Opening Comments have repeatedly documented the deficiencies in the GRC process and welcome the opportunity to provide guidance on this point. At its core, SDCAN offers the following three summary observations:

1. Most of the questions posed in the OIR cannot be answered without establishing the nature of the business model and related specific goals and objectives for California IOUs going forward;
2. Access to interval data and "big data" by regulators and third-parties is integral to any new regulatory environment. It further requires the creation of an open-architecture platform by which regulators and stakeholders can craft safer and more reliable solutions to utility operational challenges.
3. The General Rate Case (GRC) procedure has historically been hamstrung by utility strategic gaming, as exemplified by IOU expenditures on assets and cost authorized that have no apparent use. GRCs will continue to be complex and ineffective until regulators reduce gaming opportunities.

In the last chapter, SDCAN presents some specific recommendations that include the return to a historical rate base process, a move towards investment-based regulation, longer time intervals between rate cases and two new factors by which rates of return should be assessed, among others.

A. REDESIGNING THE UTILITIES' BUSINESS MODEL

Energy utilities face unprecedented change with new technology and customer demands, prompting questions about utility business models and related regulatory issues. These twin topics, business models and regulatory issues, are intertwined. Business models show how products and services are offered, incentivized, and compensated. Related regulatory issues involve cost recovery, customer financing, utility incentives, third parties, value-added services, and asset ownership. These same topics suggest building blocks for utility business models. Business models of regulated firms and government entities differ considerably from those of unregulated firms. Because regulation changes incentives the business model of the regulated firm differs from that of the unregulated firm. In order to address the OIR's substantive and procedural questions, the Commission must offer some clarity about which, if any, utility business model will be deployed in the coming years as technology drives transformational energy consumption and generation changes.

Transformational change is inevitable as new energy technologies, greater use of communications and "smart" devices, and customer desires to adopt "clean energy" measures develop in the coming decade. Solar photovoltaic (PV) technology and distributed demand-management are decreasing in price, which allow customers to dramatically alter their energy use and loads. Recent telecommunications reforms offer examples where utilities responded to technology change, streamlined regulation, and moved many elements of their business back toward the unregulated firm structure. And Google's recent re-entry into energy home management with its purchase of Nest is a clarion call to the reality of potential technological advances in home energy management for residential customers.

At one end of the business model spectrum is a wires-only distribution operator, i.e. a network-provider. A version of this may have most all other utility operations spun off or outsourced, including public policy obligations (e.g., for renewables and energy efficiency). The smart integrator model may be a middle ground where the utility provides retail customers with a platform to access distributed energy resources (DER). The smart integrator may use a common architecture, user protocols, and market prices.

At the other end of the spectrum is the energy services utility, based in a multisided electronic platform, a *plug-and-play interface* approach that enables multiple buyers and sellers of services to bring their capabilities to utilities and to customers. Integration and optimization of distributed energy resources (DER) and clean, renewable resources should be primary objectives to maximize consumer benefits. In this scenario, innovation should flow to customers at the speed of the market, largely through third parties.

Naturally, there are likely other models that exist within these two spectrum points. Whichever one(s) California chooses, it must make a decision about the role of regulated utilities in today's technology-driven utility markets and how IOUs will be expected to adapt their business model to enable them take advantages of opportunities provided by these developments.

For example, if the Commission envisions that utilities should begin to form or move more competitive parts of their business into unregulated affiliates, then the scope of the GRC changes and the extent to which safety and reliability is evaluated becomes more market-driven than regulator-driven.

If the Commission chooses to continue the integrated utility model then it will likely need to craft incentive-based oversight that incorporates reliability, safety and environmental goals and the outcomes to support those policies. Many in the energy regulatory arena seem to agree that process-slowed regulation has become a tether that constrains adoption of the many important gains in innovation, integration, and optimization. New business models and regulatory structures will likely be necessary for greater efficiencies, streamlined regulation, and innovations available from thriving firms, each of which can benefit all. But without clarity about that regulatory vision, answers to most of the questions posed in this OIR will prove elusive.

For example, the OIR asks for comments on the length of intervals between GRCs. That will depend upon the structure of utility operations and existence of incentive-based oversight. The OIR asks to parties to comment upon reduction of

GRC complexity. Given the current utility business models, GRCs will continue to be complex as the utilities seek creative ways to game the current regulatory oversight. (See *Gaming* discussion below). SDCAN suggests that the most effective way to reduce complexity would be to direct utilities to change their business models in such a way that regulatory oversight streamlined and state energy goals are better achieved.

In response to the comments of the parties, the Commission should establish that it wishes to integrate and optimize distributed energy resources (DER) and encourage increased use of renewable resources to maximize consumer benefits. It should also announce its intent to accelerate the flow of innovation to customers at the speed of the market, largely through third parties. How data is made available, including methods to "port-out" key information flows, must also be addressed.

Consistent with those objectives, the utility business model should deliver maximum benefits to customers and enable the optimal use of competitive third parties. Utility outcomes and shareholder incentives should be directly related to key policy and consumer objectives, defined by a set of agreed upon indicators and metrics that could be honed by stakeholders with the assistance of the Commission.

Once those indicators and metrics are established, the Commission could begin shaping shareholder incentives that encourage maximum benefits for consumers, transparency in ratemaking and particularly to reduce the risk of cost increases to consumers. The potential uncertainties and risks with increased costs should be defined *a priori* as condition of cost recovery, and evaluated much as *value-at-risk* (VAR) is used for supply-side resource procurement (i.e., using probability distributions). Allowed rate-of-return for the utilities should reflect the extent to which policy and consumer objectives are achieved, including risk reduction, innovation, and efforts to accelerate market transformation.

The Commission should also establish that it expects utilities and third-parties to offer a set of pricing options to all consumers in the form of alternative tariffs, providing consumer choice in the *way* they take electricity services. A move to outcomes-based regulation should enable ratemaking to be streamlined and for regulators to better gauge utility performance.

Outcome-based regulation is not a simple task. This Commission has attempted PBRs and other incentive mechanisms in the past with, at best, mixed success. Largely because of *asymmetry of information*, utilities hold a significant knowledge advantage over regulators and other stakeholders in this process, to wit:

1. Base-year indexed incentives reflect a cost structure that the Commission is to presume reasonable. However, the IOUs know more than the Commission about what it cost to run the utility in the base year and the base-year has consistently be inflated through utilities' selective expenditure patterns.

2. Cost escalation factors are generally based on two external data services. However the IOUs know more than the Commission about how its actual costs will compare to the external data.

3. The capital-related cost adjustment mechanisms are intended to "reflect the cost of plant additions." IOUs know more than the Commission about its capital expenditure trajectory and can readily game capital expenses.

4. The Commission's experience with "Z-factor" type adjustments has been a chequered one. It draws the boundary between controllable and uncontrollable costs, putting the full risk of the latter on the customers. IOUs know more than the Commission about what it can control and what it cannot.

5. The "earnings-sharing mechanisms" generally determines the portion of savings, relative to the base year costs, that IOUs can withhold from ratepayers to increase its return on equity. IOUs know more than the Commission, or other stakeholders, about their ability to cut costs relative to the base year. Similarly, with "productivity-sharing mechanisms" IOUs can use expenditure timing to affect earnings levels.

6. Market-based indexes are often skewed because utilities are solely self-interested, thus, they act very conservatively and ignore California's business environment. Incentives tied to market-based indexes often encourage risk-averse management objectives when the current utility markets should be incented to promote technology, entrepreneurship, and future state opportunities (e.g., for clean energy).

Absent comparable access to -- and mastery of -- this utility information, the Commission cannot credibly assess the utility's performance, especially the realistic boundaries on its obligation to improve. The knowledge gap disables the Commission both from establishing realistic standards, and from designing compensation schemes that induce the utility to comply with those standards.

The purpose of regulation is to deal with the risk that private behavior will diverge from public interest. That is why we have speed limits, restaurant inspections and utility regulation. The problem of divergence is enlarged by information asymmetry. The greater the differential (and the greater its role in decision making), the greater the utility's temptation and opportunity to exploit it. By holding back performance data, by deferring performance improvement in the hopes of higher rewards later for reducing costs relative to external indices, and by timing investments and rate cases to maximize net income rather customer welfare, the utility exploits its knowledge advantage without benefiting the public interest. This combination of information asymmetry and customer captivity requires a regulatory solution -- either a reduction in the asymmetry or a lessening of its influence.

The Commission will need to forge some new ground in utility regulation in order to avoid the well-documented trapdoors in current incentive regulation. For that reason, the move towards a network-based utility model offers some attractive regulatory benefits. As will be set forth below in the *Recommendations* section, there are a number of adjustments to the Rate Case process that might prove beneficial. But without clarity about the preferred utility business models, the benefits from these adjustments will be muted.

B. *ACCESS TO INFORMATION BY REGULATORS AND THIRD-PARTIES IS INTEGRAL TO ANY NEW REGULATORY ENVIRONMENT.*

No matter which regulatory model is adopted by the Commission, regulators will need to affect greater access to information / data and make it available to the market in order for a new regulatory paradigm to provide more reliable and safe utility services. Moreover, regulators need to move away from regulatory fragmentation (silos) in order to ensure better integration of regulatory policy. SDCAN submits that any redesign of the utility business model and regulatory mechanisms cannot be achieved in separate silos and regulatory proceedings, as proper regulatory calls for movement of the systems many parts at once. The latter point is one about which the Commission is highly attuned but it has encountered difficulties in overcoming the undesirable silo effects.

One important paradox that confronts regulators is that in the new Smart Grid world, utilities will have access to much greater operational and usage data than in any previous regulatory era. This "big data," including interval metering data, takes on much greater importance, but also presents much greater accessibility challenges. Access to "big data" is increasingly important to the nascent energy services marketplace. The Smart Grid world will increasingly be a participatory network of service providers and customers, with multiple applications. One common platform that can connect to generation, transmission, distribution, and customer-owned assets using a standards-based, modular design can unlock a wide variety of capabilities.

New platforms need to be designed to link large parts of this emerging value chain for resource integration, optimization, information, customer access, and third parties grid interface. Information aggregation will be highly valuable, whether device based or portal based.

Additionally, the expansion of utility DER and new consumer services has prompted the use of innovative third parties to provide technology, support, and services at multiple levels. Utilities actively procure and “plug in” third parties to provide many of the DER and customer services that are now available. Retail appliance companies are also used to enable greater penetration of DER. This and other marketing channels can be used to target “hard-to-reach” customers and deliver major energy efficiency benefits (e.g., with flat-screen TVs). “Big data” can be processed to enable remote, automated customer energy audits, bolster related DER marketing plans, and achieve other value-added services (VAS) and related tasks. Third parties’ smart grid services add other dimensions, such as for automated voltage correction, remote customer energy management, and choreographed control of loads. The potential for further development of new VAS from DER and the smart grid seems almost limitless, particularly as costs decline and uses are simplified.

“Big data” also takes on a direct effect upon the efficacy of the GRC process. Two specific problems in GRCs are the budgets and incentives to spend capital as a result of rate-base, rate-or-return incentive. SDCAN submits that IOUs have a compelling financial incentive to build huge new sub-transmission level transformers that are either 1) never to be actually purchased and used, or 2) purchased and connected to the system but for no real purpose, except to drive up rate-base and earnings. These constitute huge dollars, and nothing is usually done about it, as regulators have limited in-house expertise about how to locate transformers and distribution reconductoring. This is a screaming problem that demands resolve, both because of the size of the dollars involved and the misallocation of resources into old transmission and distribution capital instead of doing advanced integrated demand side management (IDSM).

Second, a large amount of distribution (and transmission) related capital, including theses transformers, can be directly backed out through new software, but this severely threatens to lower IOU rate base. The tradeoff is clean, much lower cost DSM, with shorter life-cycles (which will be replaced by even more efficient DSM in due course) or purchase/installation of much longer-life, and hence sunk, traditional distribution capital that remains as an albatross around ratepayer's necks for many years to come. Historically there is no larger single budget item in any GRC than the distribution capital cost budget. Accordingly, this should be targeted and brought way down through the use of IDSM. Imagine simply transforming distribution capital (budget) to DSM, with all the additional benefits that will result for generation reduction, transmission reduction, GHG reduction, etc. – a real win-win for consumers and society.

Regulators must resolve to work with the IOUs to develop greater access to "big data" by regulators and third-parties. SDCAN submits that the standardizing of this data is more properly the purview of either a non-profit or academic institution that submits to oversight by the Commission. Just as Google developed an open-architecture Android platform by which developers could offer mobile applications and services to consumers, the Commission must oversee the creation of an open-architecture Smart Grid-fueled data platform by which regulators, consumers and third-parties can better understand and apply IDSM strategies to electricity reliability and safety challenges.

C. GRCS WILL CONTINUE TO BE SADDLED BY COMPLEXITY IF GAMING OPPORTUNITIES REMAIN

Current GRCs are hampered by significant factors that will not be resolved through incremental adjustments of GRC process; each of these factors promote managerial gaming by IOUs. They include:

Manipulation of Spending Forecasts

When a utility forecasts a 10% spending increase in the future, but in reality cuts spending by 5%, the utility's forecast, no matter how well defended by the utility managers who developed it, might just be wrong. The majority of GRC-related disputes boil down to a difference in forecasting technique where the utility and intervenor each insists that their preferred technique is more reasonable. The

Commission must resolve such disputes based on which technique provides the most reasonable forecast for the costs in question. For example, twice, SDCAN's experts have identified instances where the IOU will produce cost forecasts that were substantially higher than the recorded 2010 costs. In at least one documented case, a separate process conducted in approximately the same time frame, by the same utilities' senior management team developed utility's budgets that diverged from the forecast budgets presented to the Commission in the related GRC. And therein lays the problem – the approach used for the GRC produces that was substantially higher than the recorded costs, whereas the approach for internal budgeting purposes produced forecasts that nearly matched the recorded costs. While the utilities may well prefer use of their rate case planning process, the Commission should look to achieve something closer to the level of provision reflected in the internal budgeting numbers, or a better process to reconcile dollars requested and dollars spent.

The concept of future test year regulation has morphed from a system designed to enable the utilities to receive rates that would not be eroded by inflation before they were put in place into a feeding frenzy of utility management and shareholders at the expense of ratepayers. In the 1980s, test year O&M expenses were typically based on either the last recorded year or some type of trend (if costs were rising) or average (if costs were fluctuating) plus inflation. Management requests for higher budgets were permitted but were generally few and far between. The Commission was pragmatic and searching for the truth – using data from the year after the base year to test the reasonableness of utility forecasts on a routine basis. This method of forecasting places ratepayers at a massive disadvantage and overwhelms the Rate Case Plan. A proper evaluation requires review of all of these individual requests in the same time frame, which provides both simpler and a more transparent rate case process. As discussed below, SDCAN urges the Commission to return to historical rate base methodology and address new investment in a different manner than past approaches that are needlessly complex, reduce transparency and hinder evaluation.

Reorganization

Three times, in three rate cases, Sempra utilities have chosen to reorganize in the midst of a rate case cycle, thus making costs and expenditures untrackable.[1] Consistent with this, increasingly IOUs are resorting to never-ending corporate reorganization, continual accounting shifts, and the proliferation of shared services accounts, each with its own forecast. Commission review of the utilities' showings are complicated by these factors, each of which increases the risk that faults in the data underlying the forecasts will go undiscovered due to no reason other than the circumstances of their presentation, largely that the context has been changed. Part of the standard analysis in a GRC compares the utility's past funding request for a particular activity and the

[1] Sempra reorganized in 2010, 2005 and 2002. The result is that each Sempra GRC in the past decade has faced reorganization-related challenges. The 2002 reorganization (plus the end of merger savings) rendered data underlying the test year 2003 GRC almost completely artificial. The 2002 reorganization also infected the test year 2008 rate case, as there were only three years of decent historical data available for analysis. In 2010, Sempra's reorganization challenge included the shift of activities that had been recorded in corporate centers but would now devolve to the utilities. While Sempra promised that the associated cost shifts offset each other, it was very difficult to verify this claim, in part because the timing of the reorganization in 2010 meant there were no valid historical data for a number of accounts.

amount the utility actually spent to pursue that activity. But it is not possible to compare what IOUs asked for and what IOUs spent from the last rate case because the utility revised its entire accounting structure to enable a shift from a system based on FERC accounts to an SAP system.

This has at least two implications that frustrate the Commission's effort to develop a reasonable revenue requirement. First, if the utility requested funding for a project in the last GRC and such funding was, at least implicitly, included in the authorized revenue requirement, inclusion of a similar request in this GRC would raise deferred maintenance issues. The shift in accounting systems increases the risk that some of the funding requests here represent the product of deferred maintenance that should not be funded in rates a second time, but will not be identified as such.

Second, as discussed previously, the comparison of what the utility requested and spent on certain activities in the last GRC cycle can be a valuable tool for assessing the credibility of the utility's requests here. Again, accounting changes that differ from recording by FERC accounts renders such an assessment far more difficult and complex. In future rate cases, the Commission must compel all California IOUs to adhere to FERC accounting standards or another uniform code of accounts.

Excessive Granularity

In a 1999 Sempra GRC, intervenor experts alerted the Commission that:

"It is important to recognize that this case is 'rate increase by a thousand cuts'. By our preliminary count IOUs proposed 56 adjustments to 1996 recorded expenses, upward adjustments totaling $32.8 million and 10 downward adjustments totaling $1.6 million.

It is very likely that a number of errors have slipped through IOUs's calculation, even after UCAN has taken issue with 25 of IOUs' adjustments."[2]

That 1999 testimony proved prophetic. In SDG&E's subsequent GRC there were literally thousands of individual adjustments. Account 903.1 alone for SDG&E had 31 separate adjustments that are further subdivided into 45 sub-adjustments. Many of the sub-adjustments were themselves made up of several sub-sub-adjustments. Utilities have been known to routinely packages together three to five, and even occasionally as many as ten separate sub-adjustments (or sub-sub-adjustments) under a single heading. Such packaging hindered the ability of the Commission to review the reasonableness of what is contained under that heading. And it did not help that the headings associated with the adjustments often bore little resemblance to the content of the adjustments – misleading regulators into skipping over problem areas. Increasingly, IOUs have submitted details and complex filings designed to make evaluation and monitoring difficult.

This isn't coincidental. In the past the Commission has acknowledged that, while the utilities have the burden of producing evidence and proving the reasonableness of their requests, in reality those burdens are reduced where no party disputes a request. It seems this created an incentive for the IOUs to maximize the number of individual requests and it's likely to minimize the percentage of requests that get effectively reviewed and disputed. This is why the Commission will continue

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[2] A. 98-01-014, Testimony of W. B. Marcus on Cost of Service for UCAN, page 16

to see thousands of diminutive adjustments seeking to support huge increases to forecasts. In future GRCs, the Commission should establish a minimum adjustment or minimum account threshold, under which adjustments may not be sought.

Complexity of Shared Services Accounts

Utilities have moved to holding company structures which have impeded the Commission's ability to review operations on a cost of service basis. Shared services accounts are perhaps an unavoidable element of a GRC where two utilities operate as affiliates of the same holding company. In the most recent Sempra Utilities GRC, the applicants presented 305 different shared services accounts for review. Of this number, 242 had annual amounts of less than $1 million – an average of $374,000 each, to be precise – and they were allocated slightly differently between SoCalGas and SDG&E. In other words, to get a handle on the reasonableness of the $91 million of costs recorded in these areas, intervenor were compelled to separately analyze each of 242 accounts, then the Commission would need to review each resulting recommendation to adopt the appropriate forecast, so that 305 different entries were made to the Results of Operations model. Conceptually, shared services can offer a cost-reducing benefit to ratepayers. As practiced, it is not at all clear that the shared services cost allocations serve a beneficial purpose and they certainly add complexity to the GRC process.

Productivity

IOUs traditionally undervalue productivity gains. The overly modest productive forecasts offered by IOUs in their GRC applications defy business logic and the realities of increasingly technologically-driven electric operations.

Threshold Questions To Reduce Gaming

As discussed in earlier chapters, information asymmetry and dispersion of issues across numerous proceedings (silos) have been major contributors to GRC gaming by IOUs. The rampant gaming of the regulatory process will continue unabated without significant reform. However, there are two threshold questions, not expressly raised in the OIR, that need to be addressed before GRC reform is affected:

1. How does a commission pick the quality level that defines the utility's obligation to provide reliable and safe services?
2. Do the existing multiple mechanisms for standard-setting and cost recovery work well together?

As to the first question, if compensation is for performance, the Commission must define performance. Performance is not just about cutting cost or keeping lights on; it is about defining the customer experience, the supplier obligation, and the most effective ways to carry out that supplier obligation to produce the customer experience. As discussed above, the new business models must also incorporate the state's commitment to safety, reliability, demand-side management, renewable power, transformative change and market-based solutions.

In a competitive market, the required performance level is, circularly, whatever level customers require, below which they choose to purchase nothing, or seek a different supplier. By definition, that level is set by customer preference and competitive alternatives. Below this quality level, the seller loses customers; above that quality level, the seller can earn higher returns by raising prices or attracting more customers.

Those higher returns do not last forever, however; as discussed above, unless that seller's uniqueness is due to a patent, trade secret or some other unique feature unachievable by competitors, the extra return is wiped out over time as competitors observe, learn and improve. The result of this constant pressure to improve should be constant improvement in service quality, constant downward pressure on prices, and increasing use of innovation at the speed of the market. This is how it should work in private markets. This is not how it works in California's regulated energy market.

It is these pressures that regulation should seek to replicate. The Commission's task is to set standards, and create processes for raising those standards over time. Before accepting any incentive proposal, the Commission should answer the following questions: For each of the major performance areas, what levels of performance that are valued by customers are the best performing utilities capable of accomplishing? What is the achievable state of the art, at reasonable cost?

IOUs approach compensation based on levels of investment and improvement relative to their own historic performance, using its information advantage to influence the level of supra-normal returns for its shareholders. That won't work in the coming transformational period. The better approach is objective and outward-looking: computing compensation based on the relationship of the utility's performance to top-performing utilities, using metrics that a customer with choice would use, just as a competitive market would do. Once the commission sets the required quality level, *i.e.,* normal performance, the utility becomes obligated to perform at that level, in return for which it receives prudent costs and a normal return. Any other approach rewards the utility for holding back normal performance improvements, then offering them in return for a higher return -- exactly the opposite of what a competitive market does.

Determining the quality level is not only about setting a standard, such as "average," "above average," "excellent" or "first quartile." Quality also is defined by innovation and creativity. The Commission should expect the utilities to remain alert to new technologies and new service offerings, especially those that empower customers to make efficient decisions. When those new technologies and services are produced by competitive market companies, a consumer-oriented utility will buy from those companies, rather than delay customer benefits until the utility itself catches up. The utility would still earn a normal return on its own investments, but the profit on these other services would go to those in the market best able to serve the public. That fact itself – the utility foregoing returns because non-utilities did the job better -- will induce the utility to improve.

Finally, there is the challenge of integrating multiple mechanisms for standard-setting and cost recovery so that they work well together. The general rate case is only one of several places where performance and compensation intersect. There are power purchase cases, riders and surcharges, energy efficiency obligations, power plant performance incentives and other measures. The Commission will want to ask whether this multiplicity of methods, of obligations, cost recovery mechanisms and other motivators, all intended to boost performance in different ways, is sufficiently inter-related that all involved understand their interactions and effects. To award extra incentives in a general rate case, disconnected from any notion of performance other than cutting costs, will not produce this understanding and will likely not be fruitful. It is an approach that has led to the silo complications discussed earlier.

D. SDCAN RECOMMENDATIONS

The Commission can consider a number of GRC modifications aimed at reducing complexity. They are suboptimal if not accompanied by thoughtful changes to utility business models and to how "big data" is utilized by the market. SDCAN recommends that the Commission issue a decision requesting further comments about the role of regulated utilities in today's technology-driven utility markets and how IOUs will be expected to adapt their business model to enable them take advantages of opportunities provided by these developments. In addition, SDCAN recommends a number of procedural changes to the GRC process.

#1: Return to a historical test year adjusted for a limited number of macro-level known and measurable changes.

Current reliance upon forecast test year methodology is adding unneeded complexity to the GRC process. Future GRC filings should be based upon a historic year adjusted for known and measurable changes with a high burden of proof to change costs from the test year.

The evolution of the California rate case since 1995 has spawned a completely dysfunctional regulatory process. Utility GRC applications have become a poster-child case for substantial revisions to the rate case process. They require extreme micromanagement by the regulator reviewing requested spending, which makes regulators understandably uncomfortable with denying utility requests. SDCAN's experience suggests that forecast test year applications make it is extremely easy for the utility to game the rate case, and extremely difficult for the regulators to review filings carefully. It also can be expensive and time consuming for utilities, whose costs are then passed on to ratepayers through rising regulatory affairs budgets. Instead, SDCAN recommends a return to the historical test year method, in which:

- The utility files costs based on a historic year.

- It adjusts for known and measurable changes by normalizing or removing one-time expenses in the test year.
- It can add a limited number of **known and measurable** post-test year changes (no more than two or three dozen based on my review of rate cases in other states – not thousands, and known and measurable changes rather than requests based on speculative forecasts).
- It could receive inflation and unusual increases or decreases such as pensions or rapidly shifting healthcare costs, but it would bear a high burden of proof to change costs from the test year other than for inflation.

California is one of the few states that tolerates the "forecast test year" process and, as this case has amply shown, there are serious deficiencies in this practice that compels reexamination by the Commission. And California is practically alone in using the elaborate forecast that the rate case game has become in this state. A move away from complex rate filings could allow processing in 6 to 9 months, like cases in Nevada and Arkansas.

#2: Move to Investment-Based Regulation

SDCAN submits that if the Commission is serious in its objective to transform California's investor-owned utility distribution network into an intelligent, integrated network enabled by modern information and control system technologies, it must reduce its reliance upon a cost-plus rate case cycle paradigm. SDCAN recommends an "investment-based" approach to future GRCs similar to the applications submitted by the state's IOUs. In these applications, the utilities presented a long-term "investment plans" that ensured that utility expenditures did more than just build rate base and increase profits for the utilities, but also paid for themselves through greater efficiencies and improved services for customers. This model was also used, to a limited degree, by the Commission in evaluating the IOUs Smart Grid investments (A. 11-06-006), but that statutory-mandated review didn't evaluate the reasonableness of IOUs costs nor require any degree of prioritization.

SDCAN recommends that the Commission review a process that it currently undergoing development in Massachusetts. While the proposed Massachusetts model is limited to smart grid investment, SDCAN suggests that it could be used, in tandem with historical rate base methodology, for all future network investments by IOUs. The Massachusetts Department established four objectives (to reduce the effects of outages; to optimize demand; to integrate distributed resources; and to improve workforce and asset management) and then asked the IOUs to use a "business case" approach in its presentation of proposed network upgrades.[3] However, the Department declined to adopt cost recovery models that incorporate a future test year based upon projections,[4] and chose to use a capital expenditure tracking mechanism instead.[5]

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[3]Mass. Dept. of Public Utilities D.P.U. 12-76-A December 23, 2013 order
[4] Id, p. 26
[5] Id, p. 28

In essence, rather than granting IOUs a lump sum of money for all distribution operations combined with a "trust us, we'll spend it well and if we can squeeze out any savings we might share it with customers", the Commission has an opportunity to approach network service operations differently. It can insist upon IOUs submitting a business-plan type application seeking "investment" in maintaining and/or upgrading the distribution grid, much like IOUs did in A. 11-06-006. The utilities can make a showing of how the investment will pay for itself and ratepayers, effectively, made whole, as if they were partners in the investment.

Each investment plan will, much like their Smart Grid plans, identify specific technologies and explain how it fits in a greater plan to move to an intelligent, integrated network, an adoption plan for utilizing the technology, projected quantification of the return on this investment and a joint-risk sharing plan, similar to that adopted by the Commission in D. 07-04-043. Use of investment plans will give the utilities greater incentives to take the risks in these emerging technologies and will accelerate movement to embracement of Smart Grid functionalities than will inflated revenue applications extended from three to six years. Each major investment offered by the IOUs would be supported by an eight-step analysis:

- Identify the problem to be solved or objective sought to be achieved
- Collect and analyze the real world data to confirm or refute the problem
- Identify or develop the goals/objectives to be achieved and metrics for those goals
- Conduct a cost/benefit analysis for the various customer bases

- Clearly articulate and quantify the costs to be borne by the targeted customer and the benefits to be reaped
- Present the applicable benefits to the targeted customers whether it be products or pricing options and identify and analyze alternative solutions for each customer class
- Design and estimate the costs for a Pilot Project
    - Conduct a Pilot Project
    - Develop a comprehensive Project plan to manage the process and track the results
    - Identify measureable goals, metrics that will measure progress toward the goals, and target values for the metrics
    - Modify the pilot based on interim results if necessary
- Analyze full pilot results and determine whether to proceed with full deployment based upon the actual data.

Where the IOUs apply such an analytical construct, the investments would be presumed prudent unless shown otherwise by intervenors. Where this analytical construct is not offered, the Commission would deny any opposed investment.

In private markets, it is common to expect that a request for capital funding is accompanied by a clear and detailed assessment of the business goals along with metrics to measure progress toward those goals. It is also expected that a company seeking outside funding provide investors with a detailed cost/benefit analysis to quantify the value of the investment. There is no difference in how a utility should approach a capital funding request from its customers. A "Smart Grid" deployment should seek to quantify and deliver benefits to customers commensurate with the requested investment and ultimately be accountable for its success or failure. Granted, there are some Smart Grid investments which may not necessarily prove to be fully cost-effective and yet can be justified on the basis of long-term benefits or synergies with other related investments. So while cost-effectiveness is not an essential element in a project, there is a compelling argument that the company should endeavor to determine the degree to which the project could be cost-effective.

The Commission serves, in part, in a role akin to the Board of Directors of a private corporation. While the Board generally avoids playing a management role, it does represent the concerns of the shareholders (or in a regulatory construct, the concerns of the public) and works to ensure that management is applying reasonable and thoughtful business principles when it develops and meets its business objectives. In tandem with encouraging IOUs to seek to manage their costs s (and rate base) through an investment plan approach, the Commission can also move towards the modified historical test year approach discussed above

#3: Use of Reopeners Combined with Longer Intervals Between Cases

In the event that the Commission were to consider a longer period between rate cases with a fairly conventional attrition mechanism, the following should be considered. A rate case deals with a limited future period. The length of that period depends on a number of decisions, e.g. the utility's decision to file rates, a consumer representative's decision to file complaints, and/or a commission's decisions to initiate a rate case. Performance has different time dimensions. Payback periods vary for new meters, for employee education, for a purchase of in renewable energy, and for creating a new staff division relating to technology. None of these performance time periods bears any connection to rate case time periods. As a result, there are multiple mismatches between the period in which rates are in effect, and the periods necessary to realize the benefits from expenditures. There is a legitimate concern that this time period mismatch creates a risk-reward mismatch.

Ideally, regulation should induce a company culture of continuous cost-consciousness. Calibrating rate case scheduling with payback periods makes sense in theory, but there are two problems in practice. The company cannot anticipate every cost-saving expenditure at the time that a rate case is prepared; and not every expenditure matches neatly with a distinct rate case schedule. The solution lies somewhere in the intersection of several factors: clear Commission expectations, distinctions between obligatory performance and extraordinary performance, general rate cases, and riders for specific costs. Incentives for short-term cost-cutting; returns unconnected to performance; information asymmetry; and a culture of withholding productivity for higher shareholder rewards, do not produce a public interest solution. At a minimum, SDCAN recommends that a re-opener is needed to provide IOUs ratepayers with additional Smart Grid benefits associated with operational efficiencies beyond those projected in the utilities' Smart Grid submissions.

#4: Setting Incentive-Oriented Rates of Return

As discussed above, SDCAN suggests that rates of return should be computed based upon two factors. First, they should be objective and outward-looking: computing compensation based on the relationship of the utility's performance to top-performing utilities, using metrics that a customer with choice would use, just as a competitive market would do. Second, they should be supplemented by the extent to which policy and consumer objectives are achieved, including innovation and efforts to accelerate market transformation.

#5: Other Modifications to GRC Process.

SDCAN offers a number of other specific modifications to the GRC process that are discussed more fully above. A summary of the specific recommendations are:

- In future rate cases, the Commission must compel all California IOUs to adhere to FERC accounting standards or another uniform code of accounts.
- In future GRCs, the Commission should establish a minimum adjustment or minimum account threshold, under which adjustments may not be sought.
- Before adopting an incentive proposal, the Commission should the levels of performance that are valued by customers are the best performing utilities capable of accomplishing and the achievable state of the art, at reasonable cost for each performance area.
- Coordinate amongst incentive mechanisms to ensure that the multiplicity of methods, of obligations, cost recovery mechanisms and other motivators, all intended to boost performance in different ways, is sufficiently inter-related that all involved understand their interactions and effects.

E. CONCLUSION

In summary, the Commission must be mindful of the fact that the IOUs are franchised monopolies, enjoying a legal bar to competitors and free of normal competitive pressures. Regulation must seek to either replicate those missing pressures or allow the market to apply those pressures. The two following principles that should be applied to any utility rate cases are:

1. Applicants' expenses and return should be sufficient to get the work done and attract the necessary capital: sufficient but no more than necessary.
2. If the applicant knows or could reasonably know of economical expenditures (*i.e.*, expenditures whose benefits exceed their costs, including a normal return), it is obligated to make those expenditures.

Armed with these two guiding principles and a move towards a clearer utility business model with, presumably, fewer franchised operations to review, the Commission is in a better position to improve the GRC process as well as bring about safer, more reliable operations.

SDCAN urges the Commission to request that parties advance preferred future business models and means by which Smart Grid-produced "big data" can be effectively dissimilated into markets. With this enhanced context, the Commission should be able to use this OIR process to devise a means by which to better regulate these future operations with "investment-based" regulation measured against a historical rate base.

Respectfully submitted, Dated: January 15, 2014

/s/

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