HANDY LAW LLC

Memorandum

From: Seth Handy
To: Public Utilities Commission
Date: February 19, 2020
Regarding: Docket 4943 - Principles for Performance Incentive Mechanisms

We write to provide public comment on the Commission's effort to develop principles for its review of proposed performance incentive mechanisms (PIMs).

Questions

There is a lot at stake here. Those impacted the most sadly have limited capacity to understand the implications and dedicate the resources to understand and/or advocate for their interests. Therefore, it seems critically important to start framing this effort by asking the fundamental baseline questions that must be fully answered and understood to provide full transparency and community understanding of the importance and the reasoning behind the policy. Some (but not all) of such questions might include:

- What do the legislative charters allow for our monopoly utilities to control and do in these industries?
- What do those charters require/expect of them in return?
- How do the legislative grants of monopoly control shape utility incentives, when considered together as a whole?
  - How do charter based economic interests in the value of natural gas comport with an intended, neutral role in administration of the electric distribution system?
  - How do charter based economic interests in transmission system investments comport with an intended, neutral role in administration of the electric distribution system?
  - How do economic interests in the value of distribution system investments comport with an intended, neutral role in administration of the electric distribution system?
  - Generally, how do chartered economic interests fit together (or not) to serve (or not serve) the public interest?
  - To the extent that there are charter-based disincentives to serve state interests, can those disincentives be corrected through PIMs?
    - If so, how and at what scale?
    - If not, why not?
    - If not, should they otherwise be corrected and how might that be done?
- How are the purposes and principles of state law, plans and policy served by the existing charters and regulatory framework?

- How are monopoly interests meant to be regulated to ensure that our utilities serve the public interest?
- What are the challenges that the Commission and other regulatory entities face in administering such regulation?
    - Do the regulators really have transparency into all of the information they need to access in order to assess the integrity and quality of the job the utilities are doing and being paid for?
    - If not, how might we accomplish better transparency?
- How can those challenges be overcome?
    - Might it be helpful to have more resources dedicated to independent third - party review and oversight of utility practices/administration of specific elements of our energy system (e.g., system planning and interconnection)?
- How (specifically) do the utilities make their money?
    - How much do they profit from each such activity?
    - What are their annual profits (individually) over the last 5 or 10 years?
    - What are they not paid to do? Do those things need to be done? If so, how are they funded/staffed and do they get done?
    - How does that all comport with the goals of state policy/law?
    - How/when does each utility make its case for what it should be paid to do?
    - How and how well is the public interest represented in those proceedings? Are they transparent and do they allow for public understanding and participation?
- Where is the funding currently coming from to provide the resources needed to fund state policy interests that are deemed necessary to complement the utilities' work? Does that allocation make sense & how does it impact the goals of state policy?
- What are the monetary and employment/operational incentives for our regional system operator?
    - How do those motivations influence their regional system management policies?
    - How do those pressures relate to and impact our state utilities and their business pressures and plans?
    - can any inconsistencies/disincentives be corrected through PIMs? If not, how can/must they be corrected?
- Why would/do monopoly interests dedicate so much funding to advertising in Rhode Island? What is the purpose? What perception are they seeking to address? Who pays for it?
- What trade organizations do our utilities participate in? What are their policy positions? How do those positions relate to our state's policy interests? Who pays for that participation? How much? Why does it benefit the State?
- How much real estate do our utilities own or control in Rhode Island (area, buildings)?
    - How and how intensively is it used to serve the utility charter and RI plans, policy, law and regulation?
    - What is the purpose of each individual holding?

    - Is each holding a necessary and the proper priority investment for ratepayer resources?
- How are our utilities staffed? Who evaluates and approves the staffing plan and how? How can the ratepaying public best understand the priority needs for such staffing?
- How much do our utilities spend on legal services? For what purposes? Who pays for those services? How does that comport with the interests of state policy?
- What was the purpose of "restructuring"?
    - What industries did and didn't it address and why?
    - What was its intended result?
    - Who has administered it and how?
    - How has that worked?
    - can any remaining disincentives be corrected through PMIs? If not, how can/must they be corrected?
- What is "least cost procurement" and what is its (intended & actual) role in the context of restructuring? Who administers it and why?
    - What are any remaining concerns/challenges?
    - can any remaining disincentives be corrected through performance incentive measures? If not, how can/must they be corrected?
    - Why has it proven so difficult to administer and implement the objectives of docket 4600 to get the evidence, conduct the analysis and proactively seek out our optimal energy choices/investments based on properly conducted and thorough cost benefit assessments?
        - Has the utility complied with the Commission's order for that?
        - Have we had the appropriate regulatory leadership to oversee the administration of the Commission's order for that?
        - How do we ensure that the public understands and has the resources to properly participate in the Docket 4600 evaluation process so as to ensure we make the best energy decisions/investments moving forward?
- What is the infrastructure safety and reliability process and how does it relate to mission and utility business model?
    - Who initiates proposed spending plans?
    - Is there any consultation regarding the public interest during the formative period of a proposal? If so, how is spending prioritized to best align with state law/policy and the public interest?
    - Who administers the plans and how?
    - can any remaining disincentives be corrected through PIMs? If not, how can/must they be corrected?
- Why do so many existing laws provide incentives for the utility to administer existing state policies, programs and goals?
    - How/why did those come about?
    - Why are program related incentives required?
    - How well do they serve the intended interests and/or the broader interests of state regulatory policy?

    - Are they consistent with a comprehensive analysis of motivation and the policy interests in transformation of the utility business model?
- What are the real goals driving all of this?
    - Is it reliability? At any cost?
    - Least cost provision of societal needs?
    - Environmental protection?
    - Economic development?
    - How well do existing policies understand such priorities and ensure that they are properly administered/met?

The public needs and deserves good and understandable answers to such questions in order to fully understand and be prepared to participate in the intended process of restructuring the utility business model through PIMs. Moreover, in an environment where those most impacted by the utility business model cannot be expected to have and/or dedicate the resources needed to fully engage with this reform process, the Commission ought to ensure proper leadership and provide a robust and transparent process with easily accessible and understandable information so the public can be certain that its interest is adequately represented and served through this process.

Without more transparency and more complete information, it is hard (if not impossible) for impacted interests to evaluate whether the Commission's proposed PIM principles are comprehensive and adequate.

<u>Context</u>

Rhode Island General Laws § 39-1-1 states that it is the policy of Rhode Island "to provide fair regulation of public utilities and carriers in the interest of the public, to promote availability of adequate, efficient and economical energy, communication, and transportation services and water supplies to the inhabitants of the state, to provide just and reasonable rates and charges for such services and supplies, without unjust discrimination, undue preferences or advantages, or unfair or destructive competitive practices, and to co-operate with other states and agencies of the federal government in promoting and coordinating efforts to achieve realization of this policy."

In 1996, the Rhode Island Legislature found that greater competition and performance-based ratemaking for regulated utilities in the electricity sector is in the public interest and would provide savings to customers and greater economic growth. It is the policy of the State to reduce fossil-fuel emissions and cost-effectively attain environmental standards, and maintain protections for low income customers as the sector is restructured. §39-1-1(d). In 2006, the Legislature found that restructuring in the electricity sector had not fully delivered on its promise and that the state's economy and the health and general welfare of its people benefit from reliable and least-cost energy supplies, and that it is necessary for Rhode Island to move beyond basic utility restructuring in order to secure, "to the maximum extent reasonably feasible, the benefits of reasonable and stable rates, least-cost procurement, and system reliability that includes energy resource diversification, distributed generation, and load management." §39-1-1(e).

Rhode Island's System Integration Rhode Island (SIRI) report described the current context as follows:

> Cost of service regulation is universally done in the US in the investor-owned utility sector to determine the revenue requirement for utility delivery service. In cost of service regulation, the regulator determines the expenses and investment necessary to deliver safe and reliable service, meeting all state requirements, and it also sets a return on equity investment in order to assure adequate availability of reasonably priced capital to maintain the ability of the utility system to do its job. This rate of return on equity investment is applied to the accumulated undepreciated rate base of the utility. This is principally the remaining book value of all the assets in the company's accounts, as well as other assets created by accounting orders, known as regulatory assets. The product of the rate base and the return on equity is added to expenses to create the utility revenue requirement. In Rhode Island, the specific capital investment requirements to maintain the system are identified in distribution planning and selected for prospective recovery of forecasted investment in the Infrastructure, Safety, and Reliability (ISR) Plan. . . Performance regulation is a <u>variant</u> of cost of service regulation. Instead of only relying on a return on equity for the amount in the revenue requirement associated with return on investment, regulators identify factors related to utility performance that can be readily measured, and a compensation or reward is available for exemplary performance relative to these factors. . .In some cases, relatively stronger performance incentives exist. One is the Energy Efficiency Program, and the other is the return on equity discussed above from distribution delivery services. National Grid delivers shareholder value if it achieves established savings targets for energy efficiency savings and runs the distribution system efficiently, and is at some risk for both over and under spending to achieve these savings. However, for other processes like SRP [system reliability procurement], there is no incentive or financial structure in place.

In the Transforming the Power Sector Phase One Report (see http://www.ripuc.ri.gov/utilityinfo/electric/PST%20Report_Nov_8.pdf), the State of Rhode Island declared that:

> Rhode Island's utility business model and regulatory framework have developed in an era characterized by relative constancy. From 1950 to 2000, demand for electricity consistently increased, technology changed incrementally, customers exerted little control over their electricity demand, electricity flowed one-way from the utility to customers, and the risks of climate change were unknown. Today, none of those factors are true. Demand for electricity has plateaued; many customers generate their own power; electricity flows to and from customers; technologies are being introduced at rapid pace; and the need to mitigate and adapt to climate change is real. In these new circumstances, it is appropriate for state policymakers to ask whether the traditional regulatory framework and utility business model continues to advance the public interest and state objectives. (p. 13)

. . . .

One indication of how the utility business model and regulatory framework are out-of-step with today's expectations for a clean, cost-effective and resilient electricity system is the electric grid's system efficiency, defined as the ratio of peak to average demand. While many industries have become more efficient over the last few decades by leveraging information technologies to more fully utilize capital investment, Rhode Island's peak to average demand ratio is 1.98, meaning that nearly half of the utility's capital investment is not utilized most of the time. . . The top 1% of hours cost the state ratepayers around 9% of spending, at around $23 million, while the top 10% of hours cost 26% of costs at $67 million, as illustrated in Figure 4. To meet peak demand, our system currently invests in solutions that are more expensive than is necessary. We have the technological opportunity to shift the hours of demand and thereby reduce everyone's utility bills. (pp. 13-14)

. . . .

This relative inefficiency is not unique to Rhode Island. According to the U.S. Energy Information Administration, New England's wholesale electricity market has the fastest growing gap between peak and average electricity demand. . . .For both Rhode Island's electric distribution system and New England's wholesale electricity supply market, the gap between peak and average demand means that capital assets are not fully utilized, increasing costs for customers. . . . The distribution system's relatively low system efficiency has a significant impact on the overall cost of electricity for customers, and therefore the public interest. There are four main ways in which low system efficiency increases system costs. First, the cost of energy in wholesale markets is highest during hours of peak use. Although reduced demand by Rhode Island customers may not have an impact on regional prices, it is more valuable to customers to reduce energy during the hours when it costs most. Second, low system efficiency means Rhode Islanders pay more in annual forward capacity market charges than necessary. Third, low system efficiency means we pay more in monthly transmission charges than necessary. Fourth, low system efficiency means we use our distribution system unevenly, building it bigger in some places to meet peak demand, creating additional cost. (p. 15)

. . . .

The primary financial means through which the utility can grow its business and enhance earnings for shareholders is to invest in capital projects. This bias, created by the regulatory framework rather than by the utility itself, discourages the utility from seeking more efficient solutions that do not depend on large capital investments (p. 16). . . the current regulatory framework does not incent the utility to maximize integration of DER [distributed energy resources], which would reduce customer exposure to increasing wholesale supply costs and also increase the region's energy security. That is, the regulatory framework may not sufficiently incent the utility to build a DER-centered system, consistent with the

> state's Least-Cost Procurement statute. Instead, under the current regulatory framework the utility neither benefits nor is penalized from increasing electricity supply costs that customers pay. (p. 18)

The report concludes its section on the Utility Business Model with this recognition:

> The proposed robust performance incentive mechanisms are designed to leverage the utility to maximize its overall return on equity to achieve state objectives that will benefit ratepayers. However, even in the presence of these incentives, there will remain an inherent financial bias for the utility to apply capital expense solutions rather than operational expense solutions, because the utility's authorized return on equity applies to capital expenses, not operational expenses.

Our utilities administer our energy system while openly conflicted by its goal to maximize profits from large capital investments emanating from centralized generation, transmission, distribution and natural gas interests that are impeded by the proliferation of distributed energy resources. Any principles for the implementation of PIMs ought to consider this context. PIMs ought to move us toward the opportunities associated with displacing cost of service model with incentives better aligned with Rhode Island policy and a future that better reflects such economic realities. PIM principles that do not transition away from the cost of service rates, cannot be expected to fully resolve and align conflicting incentives. PIMs will not generate the real drive for the transition contemplated in Power Sector Transformation unless they work to displace the traditional cost of service approach.

The Commission's Guidance Document issued in Docket 4600-A1 directs the consideration of goals by proponents and opponents in matters involving the Company. PUC Guidance Document, Docket No. 4600-A (Sep. 6, 2017). Those goals include:

- providing reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels);
- prioritizing and facilitating increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits;
- address the challenge of climate change and other forms of pollution; and
- align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives.

In that guidance for implementation of docket 4600, the Commission also adopted principles to be applied in assessing the reasonableness of rate design. Those principles include:

- promote economic efficiency over the short and long term;
- empower consumers to manage their costs;
- use designs that are transparent and understandable to all customers;
- ensure consistency with policy goals (e.g. environmental, climate (Resilient Rhode Island Act), energy diversity, competition, innovation, power/data security,

least cost procurement, etc.);

- promote economic efficiency over the short and long term.

This is a critical moment in the history of electricity regulation and markets in Rhode Island. PIMs can and should help set the tone and establish the foundation for the implementation and realization of important policy priorities. Incentives send price signals that influence customer behaviors and guide customer engagement with service opportunities. They guide utility decisions and shape the relationship between the utility as a service provider and its customers. Proposed and existing incentives must be examined in light of these important effects in order to lead to rates that are just and reasonable in light of state policy. In particular, these principles should be assessed against a standard of whether they support Rhode Island's policy of moving beyond restructuring as it was understood in the past, toward implementation of Power Sector Transformation.

It is time for the Commission to initiate a proceeding to evaluate the role and operation of revenue decoupling in the context of performance-based rate making. Restructuring removed the electricity generation component of the traditional capital investment driver, but Narragansett Electric still maintains its conflicting economic interest in natural gas and transmission/distribution services. Although natural gas emits fewer GHGs during the combustion process compared with other fossil fuels like coal and oil, a significant amount of methane is released throughout the natural gas life cycle, from extraction to transportation and distribution. As a result, natural gas has a significant GHG impact. In addition, natural gas historically has been characterized by volatile commodity prices, and given this volatility, expanding gas service can have a direct, negative impact on ratepayers. Furthermore, natural gas is not guaranteed to remain cheap for the useful life of the natural gas infrastructure investments that AGA supports. Taken together, natural gas expansion is demonstrably not in the interest of ratepayers.

Rhode Island needs to transition from traditional cost of service rate making toward carefully considered and administered performance-based earnings models. This transition, if led and done well, will enable the reduction of risk associated with operating a distribution utility that embraces and support rate innovation and third-party and customer-driven market development. We need leadership on proposals aimed at moderating requirements for plant and gas service investments in favor of competitive market growth. The Company has a history of increasing earnings and rate base investments despite flat revenue growth and has too frequently proposed initiatives with unproven customer benefits and deleterious impacts on customer uptake of efficiency, distributed generation, and other distributed energy resources.

Leaders must address the potential to reduce return on equity (ROE) requirements through revenue stabilization mechanisms and performance-based earnings, enhancing the attractiveness of the utilities to investors through revenue stabilization and upside earnings opportunities. The utilities must not propose regressive and DER-frustrating rate designs that increase non-bypassable fixed customer charges for residential and small commercial customers, weaken price signals encouraging more efficient use and self-generation, and appear designed primarily to extract monopoly rents. Utility forecasting methods too often assume that Rhode Island will fail to increase reliance on energy efficiency and clean distributed renewable energy generation. National Grid has an expensive Gas Business Enablement spending plan that is not demonstrated to improve customers' ability to control their gas costs and make more efficient gas consumption decisions and investments. National Grid gets rate recovery for trade association dues paid to organizations that actively advocate for causes opposed to many aspects of Rhode Island policy.

In sum, our utilities do a lot of the rate making work that they must do in order to secure adequate revenues to support the provision of adequate and reliable service to Rhode Island customers, but their rates are too often framed on outdated principals without due regard for the opportunity to seize a strategic opportunity to modernize the utility business model. In its last rate case, Narragansett Electric provided data that illustrated key trends in electric operating revenue, electric plant in service, and operating income. Taken together, the data paints a picture of a utility that is experiencing relatively flat sales but has nevertheless managed to consistently increase both its electricity rate base and its operating income. Operating an electric utility in a traditional manner is costly and requires significant capital investments. Reasonable income and profits attract affordable financing for these investments and enable additional investments in modernization and service improvement. But distribution utilities operate as a monopoly and have a strong financial incentive to grow revenues through rate base expansion. Traditionally, electric utilities have funded capital expansions and revenue growth through year-over-year increases in sales. System-wide economies of scale favored large solutions over small ones, centralized investments over distributed ones, utility investments over customer investments. With flat electricity sales trends, a new approach is required. The data strongly suggests that National Grid is headed in the wrong direction in Rhode Island.

Utilities face a challenge. Because revenues are flat, the traditional utility model, even for a restructured utility that does not own generation, offers little hope of continuing to increase returns to shareholders (income) through increasing capital investments (net plant) absent a willingness on the part of regulators to maintain and enhance revenue stabilization mechanisms, or to pass along revenue increases and increased rates of return (increased revenues). In the industry today, many utilities seek revenue security through increased fixed customer charges, the collection of demand-related costs through fixed charges, increased rates of return, and the dampening or elimination of price signals encouraging more efficient consumption and self-generation. In economic terms, the traditional monopoly will seek to increase the collection of economic rents.

As recognized by both the Rhode Island Legislature and the Commission, our utilities can embrace and begin to actualize an agenda of transformation. Elements of this transformation include performance-based revenue models that displace cost of service approaches, increased emphasis on customer engagement, stronger encouragement of energy efficiency and other distributed energy resources (DER) as an alternative to utility capital investments, and ultimately, market-based earnings derived from fair and competitive energy service markets. In the end, even higher rates could be justified by higher distribution platform service value and lower customer bills. But to get there, the utilities will have to trend toward, and not away from, their own transformation, and to embrace a vision of improved economics for them and Rhode Island through this change.

Electricity and gas sales growth is a thing of the past. Advanced energy efficiency and the compelling economics of DER in the hands of empowered customers mean that the value that customers realize for bill payments must increase. Utilities must take a leadership role in moving away from the traditional model where net plant investment directly correlates with utility income. Our utilities must embrace a model in which non-utility and customer investments in distribution-level infrastructure and capability is as much of a resource as utility-owned infrastructure investments. They must embrace a model in which income is related to performance in achieving the Commission' priorities for its service in Rhode Island. Appropriately crafted and implemented performance-based earnings should be fully integrated into the Company's rates in order to obtain Commission approval.

Just as efficiency audits and improvements are a logical precondition to energy production upgrades, regulatory prevention of outright obstruction is the logical and necessary precursor to performance incentive measures. Wherever the utility has aggressively sought to discourage the implementation of Rhode Island's energy plan and policies by imposing unwarranted obstacles, such interference must be weeded out. Incidents of obstruction can range broadly and include, but are not limited to:

- transmission and infrastructure safety and reliability planning that neglects upgrades required to facilitate interconnection of distributed generation of renewable energy (despite evident benefits for safety and reliability) as addressed in FERC Order 1000 and docket 4539, Order # 22174;
- regional capacity market practices that systemically ignore or intentionally undervalue the system capacity benefits and value of distributed energy resources;
- unreasonable charges that look to reduce the competitive advantage and benefits of distributed energy resources (e.g., the access fee proposed in Docket 4568, the pass through of an alleged interconnection tax from which NEC is exempt in docket 4483 Order #22957, on appeal at the RI Supreme Court and the ploy to impose transmission system studies and costs at issue in Docket 4981);
- failure to properly account for docket 4600 cost and benefit analyses as was evident in the largely unsuccessful request for proposal addressed in docket 4822 and the continuing failure to account for the locational benefits of distributed generation despite the statutory directive to do so as part of the renewable energy growth program;
- regularly repeated neglect of and failure to comply with the mandates of Rhode Island's interconnection laws.

Comments on Draft Guidance Document

I. Purpose & General Matters

It will help to be more express about the specific, existing disincentives that proposed PIMs are designed to fix. That framework might include distinction between those disincentives that can be remedied through such incentives and those that may require other structural solutions (i.e., deeper organizational/structural problems will require deep/organizational solutions that PIMs alone will not produce). It may be helpful to offer guidance on what might be more properly done about disincentives that are not able to be addressed through PIMs. As for specifically proposed PIMs, clearer explanation of the origin of the disincentive may help reviewers see whether the proposed PIM is effectively designed to address the disincentive, whether it will resolve the disincentive (or requires complementary policy) and to set metrics to evaluate and improve its effectiveness.

It also seems important to address the impact of scale in this analysis. PIMs implemented on a small scale may not move the needle on transformation or be cost effective. But, when implemented at a larger scale, PIMs may have entirely different costs and benefits and transformative impact that are worthy of implementation.

II. Applicability

In section 1, principle 3 (it may be more helpful to use different numbering for sub-bullets), who can/will adequately represent the public interest in presenting or responding to PIMs and do they have the resources needed to meet the burden? How will such advocacy be made clear & transparent to the public? Customers generally do not have the resources (time, capital) to participate in such complex, evidentiary proceedings, which is a great disadvantage to the public interest.

In section 2, principle a, we believe it very important to be more specific about how the Commission expects PIMs to relate to the allowed return on equity in rate-based investments, as discussed in our "context" section above.

In section 2, principle d, we propose to revise "gradualism" to "gradualism where warranted" in order to better acknowledge that some situations may require expedient implementation on urgent transformations/outcomes.

In section 2, principles d and e, we believe it appropriate for the Commission to recommend reform with regard to existing statutory norms/incentives where and as appropriate to provide for a more comprehensive and ordered approach to incentives. The Commission need/should not withhold its expertise on such matters, especially as informed by stakeholders and experts (after all, there are no better qualified authorities on such matters). There is a typo in the existing phrasing of the last sentence of principle e.

In section 2, principle f, the language "with consideration of. . return on equity in rate base" is oblique and difficult to understand. To be clearer, we propose to revise as follows:

> The PUC will apply the Principles to proposals for other performance incentive mechanisms with consideration of any existing incentives, <u>to remedy apparent disincentives from the existing business structure</u>, including return on equity in rte base and statutory remuneration, and <u>to uphold</u> minimum service quality standards, to the extent possible."

III. Definitions – no comments.

IV. Principles

On Principle 1, upon reflection, we agree with the Commission's skepticism and disapproval of the PIMs proposed in National Grid's last rate case. There is no reason to offer minor, added incentives at the margins of the Company's business that do not promise to get to the heart of the disincentive they purport to address and that cannot be expected to change the Company's economics or business plan in a way that will achieve the transformation we seek. Most of our advocacy in that proceeding related to the pressing need to displace cost of service and return on equity compensation with well-conceived performance incentive mechanisms that might transform the utility business model. Sadly, such transformative displacement was not contemplated in the settlement. Here we would propose to add to principle 1, that PIMs should not be used where the incentive cannot be expected to have a marked impact on resolving the underlying disincentive (deep structural problems/interests require deep structural remedies, not just gratuitous compensation). Maybe this is a revision to indicate that merely "incremental benefits" are inadequate, since we are resolved to seek benefits that are transformational.

On Principle 2 and 3, we submit that it's important to expressly state the added elements of scale and impact (cost/benefit) across sectors by adding at the end "at optimal scale for transformation and as evaluated both within and across sectors." As noted above, while a small incentive may not drive any change and therefore would not be expected to be cost effective, a larger driver of transformation may shift the framework providing new systemic benefits that overcome the costs of implementation. For example, a small-scale thermal electrification program incentive may not be cost effective while larger scale implementation may shift demand for natural gas in such a way to reduce supply/transmission/distribution costs sufficiently to provide more cost effectiveness. Moreover, the only way to see such benefits is to ensure that they are viewed across sectors (i.e., thermal demand impacting cost of electric fuel source).

Principles 2 and 3 still speak of "quantifiable benefit." It's hard to decipher how that language relates to the "consideration of" non-cash benefits as discussed in the second sentence of principle 3. My understanding of the dialogue at the tech session was that the Commission was going to be more receptive to some of the less quantifiable benefits addressed in the docket 4600A guidance than the language of that principle suggests. Might the discussion of implementation provided in docket 4600 help clarify the consideration of non-quantifiable benefits (including the internalization of externalized costs)?

We propose to add the following clause to the end of principle 4 - "and achieve the intended transformation." As discussed above, some disincentives may be so deeply enmeshed in existing structures that they will need to be addressed by review and revision of that foundation. In such cases, transformative impact may depend on changing the relevant charter/law rather than offering additional incentive/compensation.

We'd propose to delete the first sentence of Principle 5 because it is subtle and difficult to interpret. We read it to mean that the utility shouldn't be paid more than customers are paid to achieve specified benefits (for example, the utility shouldn't be paid more for investment in distribution system improvements than customers are paid to as implement distributed energy resource solutions that reduce demand on the distribution system), but are not clear on whether that's the intent. The second sentence seems to say more and say it more clearly (and also seems consistent with our comment on Principle 4).