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April 8, 2019

Ms. Debra A. Howland
Executive Director
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 18
Concord, New Hampshire 03301

Re: Docket No. IR 15-296
Investigation into Grid Modernization
Comments on Staff Report of February 12, 2019

Dear Ms. Howland:

Please treat this letter as the response of the Office of the Consumer Advocate (OCA) to the invitation issued in the above-referenced docket by the Commission, via its secretarial letter of March 13, 2019, to submit comments on the January 31, 2019 report entitled "Staff Recommendation on Grid Modernization" (Staff Report).

As you know, the Commission's Electric Division issued the Staff Report following its extended consideration of the March 2017 report of the Grid Modernization Working Group, of which the OCA was a member. Two other members of the Working Group – the City of Lebanon and Patricia Martin – have authorized me to state that they join these comments.

As you also know, the OCA filed a letter on February 25, 2019 raising certain concerns about the procedural steps recommended by the Electric Division in the Staff Report. The contents of our February 25 letter are incorporated herein by reference, although the concerns expressed in that letter are reprised here and elaborated upon in light of the technical session held on March 25 to discuss the Staff Report.

On behalf of the state's residential electric ratepayers, the OCA commends the Electric Division for its comprehensive and thoughtful analysis of the challenges presented by the quest to modernize the electric grid. As the Commission observed in its 2016 order establishing the Grid Modernization Working Group, a combination of "policies, technologies, and practices" that falls under the rubric of grid modernization can help the Commission discharge its responsibility "to ensure that the electric utilities provide safe, reliable electricity services at just and reasonable rates." Order No. 25,877 (April 1, 2016) at 2. As the Commission noted, grid modernization "can spur the development of cost-effective distributed energy resources, including energy efficiency, demand response, distributed generation, storage technologies, and more." *Id*. We share the zest of the Commission Staff for getting to the task of grid modernization at long last.

I. Procedural Issues

Our zest for grid modernization notwithstanding, we strongly urge the Commission to adopt a different procedural framework than the one recommended by Staff.

Pages 77 through 79 of the Staff Report outlines a detailed set of proposed procedural steps beginning with (1) comments on the Staff Report and continuing to (2) detailed comments and proposals from stakeholders on 13 specific issues, followed by (3) working groups to discuss those proposals, along with certain studies and efforts to coordinate the grid modernization investigation with other pending dockets, and (4) the submission of an "Integrated Distribution Plan" (IDP) by each electric utility followed by an adjudicative proceeding for each plan. Staff intends the IDPs to supersede the least-cost integrated resource plans each utility must periodically file pursuant to RSA 378:38, in light of the Commission's authority pursuant to RSA 378:38-a to "waive for good cause any requirement under RSA 378:38, upon written request by a utility."

Albeit in somewhat contradictory fashion, Staff added some meat to these bones at the March 25 technical session. Although Staff suggested that each of the topics set forth at pages 77-78[1] could become the topic of a separate working group, Staff implied there would be significant consolidation so that individual working groups might handle more than one topic. Staff is proposing that the Commission issue an Order of Notice in May instructing the utilities to file their IDPs (presumably on a single date) in May of 2020, that the working groups be convened in May 2019 so they may work for nine months and complete their efforts in February 2020. Although Staff concludes that the utilities should have a year to develop their IDPs, Staff's proposed timeline gives them only four months to do this work following the completion of the working groups' efforts to provide clarity on the 13 key issues listed by Staff.

Policy considerations aside, the Commission should reject this proposal because it is legally and constitutionally flawed.

Order No. 25,877, quoted above, explicitly ties the concept and implementation of grid modernization to the discharge of the Commission's responsibility pursuant to RSA 378:7 to assure that utility rates are just and reasonable. RSA 378:7 explicitly and unambiguously requires a hearing prior to such a rate determination. The commission cannot discharge this requirement to provide a hearing by convening working groups or other informal processes; this is why, for example, the informal processes for implementing the Energy Efficiency Resource Standard (and, with it, changes to the System Benefits Charge appearing on all electric bills)

[1] Those topics are cost-effectiveness framework, utility cost recovery and performance incentives, utility and customer data and data access, hosting capacity analysis, locational value analysis, metering, customer education, strategic electrification, rate design, DER (distributed energy resources) pricing structure, consolidated billing, cybersecurity, and annual reporting requirements.

superintended by the Energy Efficiency and Sustainable Energy (EESE) Board is always followed by an adjudicative proceeding.

As to the constitutional implications, the only explicit guidance is *Appeal of the Office of the Consumer Advocate*, 148 N.H. 134 (2002). At issue in that case was a Commission decision to approve an amendment to a previously approved special contract, between an electric utility and an industrial customer, without providing the OCA with an opportunity to challenge the extension at a hearing. The New Hampshire Supreme Court concluded that residential utility customers, whose interests are represented by the OCA, did not have "a statutory or due process right to a hearing when the PUC approves an amendment to a previously approved special contract." *Id*. at 137. With respect to due process, the Court noted that Part I, Article 15 of the New Hampshire Constitution is "at least as protective of the ratepayers' rights as the Due Process Clause of the Fourteenth Amendment" although the Court did not "engage in a separate federal analysis." *Id*. (citations omitted); *but see id*. at 139 (observing that "[f]ederal courts have consistently determined that utility customers do not have a vested property interest in the setting of utility rates sufficient to invoke the procedural protections of the Fourteenth Amendment") (citations omitted).

It would be improvident for the Commission to rely on *Appeal of the Office of the Consumer Advocate* to conclude that no due process rights are implicated here.

The sole U.S. Supreme Court precedent, relied upon by the New Hampshire Supreme Court for the proposition that consumers are devoid of *federal* procedural due process rights in utility rate-setting matters, is a 1936 decision – i.e., one issued at the height of the infamous *Lochner* era[2] – in which the high court rejected with essentially no discussion a consumer-based due process claim, reasoning that the interests of the disgruntled customers were represented by a municipality (whose rate settlement with a utility, after regulatory approval, was the subject of the constitutional challenge). *See Wright v. Central Kentucky Natural Gas Co*., 297 U.S. 537, 580 (1936). In other words, *Wright* does not stand for the proposition that customers have no due process rights before utility regulators. The other federal cases relied upon were decisions of trial courts, none of them more recent than 1975 and none of them arising in the First Circuit.

More importantly, *Appeal of the Office of the Consumer Advocate* contains no sweeping determination, as a matter of *state* constitutional law, of the sort the New Hampshire Supreme Court somewhat dubiously attributed to the federal judiciary. *Appeal of the Office of the Consumer Advocate* does *not* stand for the proposition that, in a matter implicating far broader ratepayer interests than those arising from one special contract with a particular industrial customer, the Commission is free to ignore due process. To the contrary, the Court reaffirmed a well-established inquiry into three factors when due process concerns are raised under the New Hampshire constitution:

> First, the private interest that will be affected by the official action; second, the risk of an erroneous deprivation of such interest through the procedures used, and the probable

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[2] The reference is to *Lochner v. New York*, 198 U.S. 45 (1905). For a discussion of the *Lochner* era, *see, e.g*., Cass R. Sunstein, "Lochner's Legacy," 87 Columbia L. Rev. 873, 880 (1987) ("In the Lochner era . . . the police power could not be used to help those unable to protect themselves in the marketplace"). The *Lochner* era is generally regarded to have ended with *West Coast Hotel v. Parrish*, 300 U.S. 379 (1937), upholding the constitutionality of Washington's minimum wage law.

> value, if any, of additional or substitute procedural safeguards; and finally, the Government's interest, including the function involved and the fiscal and administrative burdens that the additional or substitute procedural requirement would entail.

Appeal of the Office of the Consumer Advocate, 148 N.H. at 138, *quoting In re Richard A.*, 146 N.H. 295, 298 (2001); *see also State v. Lavoie*, 155 N.H. 477, 482 (same) and *Mathews v. Eldridge*, 424 U.S. 319, 334-35 (1976) (adopting this test for federal due process claims).

The Staff Report is rife with confirmation that the private interests at issue here are colossal. Among the matters Staff believes can be suitably addressed via informal working groups are critical questions that are typically decided in rate cases or other adjudicative proceedings: what cost-effectiveness test to apply to grid modernization investments, what cost recovery mechanisms and performance incentives should be adopted, what meter investments are appropriate, how rates should be designed, and what the cybersecurity implications of grid modernization are. Rate design questions, in particular, are often the most contested aspects of utility rate cases. Cybersecurity concerns have the potential to add billions to rate base in New Hampshire, and even in the best of circumstances (i.e., adjudicative proceedings, in which decisions are based on a defined record that has been fairly developed) are likely to be resolved in secret.[3]

Indeed, there are fundamental questions at issue here that are certain to alter the future of both how electric service is provided and how it is paid for. To cite but one key example: Why are utilities not simply obliged to modernize their distribution systems according to available technology, based on their existing obligations as utility franchisees to provide safe and reliable service at the lowest possible cost in accordance with the state energy strategy described in RSA 378:37, as opposed to creating a new category of investments that are somehow entitled to cost recovery separate and above distribution rates? *See* Staff Report at 64 (recommending a "targeted cost recovery mechanism enabling recovery of both grid modernization related O&M as well as capital investment").[4]

Given the centrality of the issues that seem to fall under the rubric of grid modernization, the remaining two *Richard* factors are easily addressed. Essentially, the questions to be addressed in this investigation are among the most significant the Public Utilities Commission confronts –

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[3] Given the importance of cybersecurity issues in both financial and practical terms, it is particularly troubling that even as Staff seeks to charge forward with its proposal for working groups, the cybersecurity aspects of the Staff Report are apparently incomplete. *See* Cover Letter to Staff Report (Feb. 12, 2019) ("a preliminary discussion of cybersecurity and the protection of the electric grid from cyber vulnerabilities is included" but "Staff continues to research and work on its findings and recommendations concerning grid modernization and cybersecurity"). The cover letter promises an "addendum" to the Staff Report (on some unspecified date in the future) that "further identifies cybersecurity issues related to the electric grid, including current or newly proposed governing standards. *Id*. The cover letter indulges the assumption that the Commission will simply approve Staff's proposed "working group" strategy and therefore promises that the "addendum" will be "included in relevant working group discussions as we move forward." At the technical session held on March 25, 2019, Staff refused to provide a timetable for the submission of the addendum, which Staff identified as being prepared by the director of the Commission's safety division. This state of affairs, with respect to such a critical aspect of grid modernization, exacerbates the OCA's statutory and due process concerns.

[4] The merits of this recommendation are discussed *infra*. The point here is merely that a grid mod 'tracker' is a big deal.

that, more than anything, accounts for why the issues remain unresolved nearly four years after the General Court directed the agency to open this docket – and the risk that customers and other stakeholders will not be fully and adequately heard via an informal working group process is vast. Again, one need look only to the EESE Board for an example of how the results of informal 'stakeholder input' processes can be disregarded. As to the Commission's interest, including the function involved and the fiscal and administrative burdens that the additional or substitute procedural requirement would entail, it can hardly be argued after four years that a regulatory agency whose very reason for existence is adjudication would be unreasonably burdened by resolving key questions via contested case procedures. Indeed, it would arguably lessen the burden on the agency to commence an adjudicative proceeding now in order to resolve the issues that are common to all of the utilities.

Staff is hardly oblivious to these due process concerns but appears to believe it is sufficient to conduct adjudicative proceedings following the submission of individual utility IDPs. But in due process terms this would be too little too late. Consequently, the remainder of this letter addresses key policy and practical questions that must be resolved prior to the submission of utility IDPs.

II. General Observations About Grid Modernization and the Staff Report

As the Commission considers what steps to take next, in the wake of the extensive work done by the Grid Modernization Working Group and, now, the Commission Staff, it is important for the agency to consider this issue in its appropriate historical and technological context. Here, briefly, is our view of that context from a ratepayer perspective. We have developed these comments with the assistance of our consultants at The Wired Group, a nationally recognized team of experts on this subject.

Since the introduction of alternating current and the power grid concept in the early Twentieth Century, utilities have always taken a simple approach to grid planning. They build systems to deliver power from an energy source to a consumer of that energy. As those systems were developed issues arose – particularly, and critically, questions of system reliability and safety. A solution was devised: build substations as the hub for protection and control. Early systems were initially protected by fuses which later evolved into oil-filled circuit breakers in conjunction with analog electromechanical relays, reclosers and sectionalizers that became the standard for protecting and controlling the grid.

These protection systems were designed to de-energize the smallest possible section of the grid as quickly as possible so as to prevent damage to the rest of the grid. One of the biggest benefits of electromechanical relays has always been their durability and long lifespan. However, in today's world, the drawbacks are that that they are slower than the new microprocessors and their accuracy fades over time, requiring regular calibration. Utilities are therefore slowly adding these new technologies as needed in areas where they are justified, i.e. when they pass a risk/cost justification test.

It would be fair to say that the power industry has historically been cautious to adopt new technologies. The reliability of electromechanical relays and the criticality of the bulk electric system only welcomed small, gradual changes to protection schemes. In the 1960s, advancements in technology made way for discrete components to be used in electric system protection. This enabled the introduction of the solid-state relay. These relays had quicker operating and reset times and no moving parts, giving them an edge over electromechanical relays. As computer-based technologies advanced further in the 1970s, a microprocessor relay was introduced in 1979. Through the 1980s, microprocessor relays were basically restricted to the theory of electromechanical relays. It took some time, but utilities eventually realized the pros outweighed the cons when it came to microprocessor relays, and the utilities introduced microprocessor-based relaying as they could justify the added expenditures, often in conjunction with new equipment installations and or required replacement of existing equipment due to failure or overload.

The point here is that utilities have been incorporating new technologies, along with new operating practices, for over a century, and they have always done so using a common-sense approach: Does the reduction in risk of an adverse event (such as a service interruption) justify the expenditure? It really is that simple.

So, what has changed? Two developments have changed the perceived paradigm.

First, although the utilities still need to build systems that deliver energy from a source to the consumer of that energy, the advent of Distributed Energy Resources (DERs) means the energy no longer comes only from a central generating source, to be delivered unidirectionally to the consumer. DERs can be anywhere on a distribution system and the power flow can be bidirectional. However, this does not change the functionality of the utility; it just requires the application of additional new technology *as needed*.

Second, utilities traditionally had consistent load growth on their systems which required capital intensive investments in new generation, transmission, and distribution facilities. Investment growth equated to earnings growth which equated to happy investors. As load growth dropped off due to conservation, and as new sources of energy production competed with central generation, utilities had fewer opportunity for investment. This meant unhappy investors.

Thus utility managers around the nation are behaving as rational profit-maximizers by now proposing huge investments in distribution; such investments are the only remaining opportunity for rate base growth (and growth in regulated earnings). The perceived complications associated with DER on the distribution system are perfectly suited to utility interests in justifying huge grid modernization investments. However, when utilities began to apply their traditional approach to project evaluation using a traditional risk/cost analysis, they found that most of the new grid modernization investments could not be justified, especially at the levels of spending that the utilities had traditionally enjoyed at the generation and transmission levels.

The solution was to separate the spending on grid modernization from the traditional "business as usual" spending. After all, 'grid mod' supports environmental goals that cannot be monetarily quantified. To keep investors happy, all a utility needs to do is convince regulators and legislators that grid modernization is (1) a good idea that must be implemented *now*, (2) too complex to be considered as business as usual, and (3) incapable of being evaluated by a typical risk/cost analysis. Even more ingeniously, utilities around the U.S. resolved that because the need for grid modernization could not be proven objectively, and that cost recovery risk was therefore high, a premium cost recovery method was needed to encourage investment.

The Staff Report filed in this docket appears to have wholeheartedly and unskeptically adopted the utilities' way of thinking. The Staff Report encourages (1) capital spending in preparation for far-off risks,[5] (2) distinguishing between "modern" and "business as usual" investment despite no real need to do so,[6] and (3) using a highly questionable "least cost/best fit" approach to evaluate grid modernization investments.

There is no reason for grid modernization investments to be evaluated using anything other than the traditional risk/cost approach (supplemented by the utility cost test). In fact, utilities need to handle the new issues of DER accommodation, or any other new priority, as they have in the past. That is, the Commission should require utilities to use risk-informed decision support (RIDS), supplemented by the utility cost test, to evaluate all proposed grid investments, be they modern or business as usual.[7]

Any proposed project can be evaluated using a RIDS model, and any type of risk – from a service interruption to a safety risk to a delay in DER interconnection requests on a certain circuit – can be incorporated into a RIDS model. Once all proposed projects have been risk-scored using a RIDS model, each project's risk reduction value per capital dollar can be compared to other projects' risk reduction values per capital dollar, enabling informed decisions regarding project implementation priority and, ultimately, justification for an appropriately-sized capital budget overall.

What does all of this mean for New Hampshire's current discussions on grid modernization and grid planning? As ratepayer advocates, we fear that Staff's views are already biased in favor of the utility perspective.[8] Adoption of the approach and perspective of the Staff Report would

[5] Staff's recommendations were directly influenced by training sessions held by the U.S. Department of Energy (DOE). Staff Report at 8. The DOE's insights may have been disproportionally influenced by early-mover states such as Hawaii, California, and Massachusetts, which were forced into the position of early-movers due to a much higher penetration of DERs than New Hampshire has experienced to date, Therefore, risks related to DER penetration may be much farther off than the Staff report appears to contemplate.

[6] For example, Eversource has been making extensive investments in distribution automation under the auspices of its reliability enhancement program for several years. In many other jurisdictions such investments are considered to be related to grid modernization.

[7] Utilities have had access to risk-informed project prioritization and selection decision support software for decades. The software allows users to establish evaluation criteria, assign weights to criteria, and to rate each project's ability to deliver various criteria outcomes. The software then calculates a benefit-cost ratio for each project, ranking them from best to worst on a list of proposed projects. Employed in an electric utility context, stakeholders can use the list to help decide where to "draw the line," making informed choices about which projects get funded, and which are left for consideration in the next IDP cycle. Risk-informed project prioritization and selection decision support can help IOUs invest in a manner that more closely resembles the practices of unregulated businesses subject to competitive forces.

[8] *See* discussion of due process concerns, *supra*. We were encouraged by the response of Mr. Frantz, director of the Commission's Electric Division, to our query about the extent to which the Commissioners themselves have been

mean that a flawed and inadequately-defined process will likely be used to evaluate the multi-hundred-million-dollar capital investment plans New Hampshire utilities are about to propose. It means that investor needs for earnings-per-share growth are about to be prioritized over customers' needs for just and reasonable rates, and over common sense. It also means that a litigated proceeding is needed now rather than later -- to protect consumer interests while the grid planning process for New Hampshire is being defined.

III. Integrated Distribution Plans as the Successor to Least-Cost Integrated Resource Plans

A key premise of the Staff Report is that Integrated Distribution Plans should replace and supersede the least-cost integrated resource plans (LCIRPs) that the electric utilities are required to file on a regular basis. *See* RSA 383:38 (requiring LCIRPs "within 2 years of the commission's final order regarding the utility's prior plan, and in all cases within 5 years of the filing date of the prior plan"). Pursuant to RSA 378:38-a, the Commission may issue an order to "waive for *good cause* any requirement under RSA 378:38, upon written request of a utility."

Staff's proposal to transform the LCIRP process in this manner has merit and is legally permissible. As you know, the OCA has long advocated the adaptation of LCIRPs to current needs in this restructured and technologically labile century, so that the process of developing these plans is no longer a rote "homework" exercise but, instead, restores the fundamental purpose of the statute: assuring that the utilities are truly planning in a coherent and least-cost manner. Staff and the Commission have also urged the regulated electric distribution utilities to make better use of their LCIRP on several occasions,[9] including directing them to identify distribution and local network service transmission facilities (circuits and substations) "ranked by need for reliability or capacity upgrades … [and] evaluat[ing] non-wires alternatives (DERs) that may contribute to [transmission and distribution] reliability or capacity solutions by deferring or avoiding potentially more costly investments in T&D infrastructure."Order No. 25,111 (June 11, 2010, Docket No. DE 09-137) at 31-32. More recently, all of the electric distribution utilities committed to filing grid needs assessments within their next LCIRP. *See* Order No. 26,206 (Dec. 31, 2018, Docket No. DE 17-136) at 10. These grid needs assessments, modeled on filings required by the California Public Utilities Commission, is the foothold from which stakeholders should evaluate early candidates for non-wires alternative pilots.

Given that the LCIRPs are due 4,5, and 10 months from now, and the projected filing date for the IDPs is at least 14 months in the future if Staff's proposed next steps are adopted,[10] the

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involved in the process of developing the Staff Report. Mr. Frantz stated that the Commissioners were not involved in reviewing drafts of the report and were "apprised of it at a very high level" at the time of its public disclosure.

[9] *See* OCA Statement of Legal Position (Nov. 1, 2018), filed in Docket No. 17-136, at 4-10 (describing each LCIRP and related Commission order for nearly a decade in which the OCA and Staff have unsuccessfully urged the utilities to integrate distributed energy resources into their distribution planning processes in a meaningful way.

[10] This timeline will be even further delayed if, as suggested by at least one utility at the March 25 technical session, the utilities would need 12 months to develop their plans ***after*** all working groups or litigated proceedings relative to non-consensus topics have concluded. Staff apparently expects the utilities to develop their plans prior to

Commission should reject any utility requests for waiver of their forthcoming LCIRP obligations. Instead the Commission should use the forthcoming LCIRPs as an opportunity to "walk" the utilities through planning for non-wires alternatives by directing each to implement a pilot before they begin to jog or run toward integrating NWAs comprehensively into their distribution planning process, which Table ES-4 of Staff's recommendation suggests will not occur until at least four years after the initial IDPs are approved. As we noted in our May 2017 Comments on the Grid Modernization Working Group Report, the New York Public Service Commission did not wait for its utilities to make significant investments in grid sensing and visibility technologies prior to directing them to implement NWAs. *See* OCA Comments in Respose to Grid Modernization Working Group (May 19, 2017) at 5-7. Instead, the New York regulators simply directed each utility to identify at least one planned capital project that could be deferred or eliminated through the targeted deployment of cost-effective non-wires alternatives such as energy efficiency and load curtailment.[11] The Commission should follow this example.

The "Stages of Grid Evolution" shown in Figure 2-1 at page 24 of the Staff Report, as developed by Paul DeMartini for the U.S. Department of Energy, provides a useful "walk-jog-run" roadmap that, if applied correctly, is well-calculated to assure that grid modernizing-measures are deployed at an appropriate pace. Although the DiMartini framework divides the evolution of the grid into three distinct phases, we do not understand this formulation as contemplating quantum leaps from one stage to the next. Rather, we anticipate (for example) that individual circuits will move from Stage 1 (low DER adoption, emphasis on reliability and operational efficiency) to Stage 2 (moderate/high DER adoption, emphasis on DER integration and operational markets) even as Stage 1 remains appropriate for other circuits. The objective should always be to upgrade the right circuits at the right time. Surgical, circuit-specific upgrades to new capabilities as needed should be the norm; across-the-board upgrades are unlikely to deliver favorable benefit-to-cost ratios for customers.

Consumers may take real comfort from Staff's assurance that, as the Working Group concluded, stakeholders can and should be "involved in pre-planning, project identification and consideration, and project prioritization." *Id*. at 45. At the same time, it would not be useful for stakeholders to become involved in every single project decision. Rather, stakeholders ought to play a role in determining *how* projects are evaluated – what risks are relevant, how much weight is attached to each such risk, what engineering standards apply, etc. Stakeholders should likewise have a voice in setting overall capital budgets, with the understanding that utilities need some leeway in determining precisely how to spend these funds. It is reasonable to expect the utilities to identify and gain stakeholder buy-in for major capital initiatives. IDP review proceedings are an appropriate forum for litigating the size of capital budgets. But we do not advocate a scenario in which utilities risk cost recovery disallowance for any capital project that was not described in an approved IDP. Micromanagement is not the objective here.

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conclusion of such discussions, which flies in the face of the collaborative stakeholder process embraced elsewhere in the Staff Report. Given that the Commission first ordered the utilities to integrate NWAs into their LCIRPs almost a decade ago, Staff's suggestion that we should wait another five years is an unacceptable outcome.

[11] *See* Order Adopting Regulatory Policy Framework Implementation Plan, New York Public Service Commission (Docket No. 14-M-0101, Feb. 26, 2015).

Unfortunately, given Staff's rejection of the Working Group's proposed consumer advisory council, it is far from clear how this stakeholder engagement will occur at meaningful junctures. Simply reacting to IDPs that have already been drafted and formally submitted is not the equivalent of engagement at the juncture when utilities are truly assessing and deliberating their options. If only because of repeated reminders tendered by the utilities during the Working Group's deliberations, the OCA is mindful of the reality that the utilities are ultimately responsible for the safe and reliable operation of the distribution grid. But that fact cannot justify a completely closed approach to IDP development, particularly in circumstances where customers will apparently be required to remit additional special charges to compensate utilities for their grid modernization efforts.

IV. Specific Content Requirements for Integrated Distribution Plans

Although the OCA agrees with the general approach of LCIRPs metamorphosing into IDPs, we respectfully suggest certain improvements to the specific requirements for IDPs as enumerated in the Staff Report. Specifically:

- Conservation voltage reduction can advance multiple objectives and offers an exceptional benefit-cost ratio when deployed and operated conscientiously. Thus, conservation voltage reduction, and a methodology to measure circuit voltage reductions from baselines, should be recognized as a distinct functionality addressed in the short term in all IDPs.

- Secure, standardized, automated data access (by consumers and authorized third parties) can advance multiple objectives but is not recognized as an objective, capability, or functionality. This subject should receive high visibility for planning purposes in conjunction with metering (long term). Consideration should also be given as to whether usage data should be updated and/or made available in near-real time.
- Hosting capacity analysis (HCA) can and should be used to radically simplify utilities' interconnection application review processes. Applications for inverter-based, non-synchronous DER interconnection (PV Solar and batteries) on circuits or laterals demonstrating sufficient available hosting capacity should not require any application-specific capacity analysis. In California, reviews of compliant interconnection applications are typically approved in just 2-3 days. Rejections are generally limited to those violating technical compliance (inverter standards, for example).
- If not properly overseen by technical experts, HCA can easily be turned by a utility into a tool to limit DER. Artificially low hosting capacities, and justification of unnecessary investments, can easily be secured through biased application of HCA/biased determination of HCA inputs. The Commission should assure that stakeholder ability to scrutinize HCA is maintained.

V. Suggested Improvements in IDP Content and Analysis

The Staff Report sets forth a workable framework for the contents of Integrated Distribution Plans. However, our review of the Staff Report suggests certain refinements to the Staff roadmap.

Table ES-3, Staff Report at 13, sets forth functionalities to be achieved via grid modernization. Pages 68-69 of the document recites a proposed standard outline for IDPs. These aspects of the Staff Report should be revised to adopt a risk-informed project prioritization and selection process in the short term. Rather than favor some types of grid investments over others, each utility should evaluate potential grid projects on the basis of their ability to achieve established objectives (reliability, DER accommodation, safety, appropriate price signals, fair and efficient rates, etc.) relative to costs. This single project prioritization and selection process, supplemented by the utility cost test, should be consistently applied to all potential grid projects. Stakeholders should have input on evaluation criteria and relative weighting.

On a related note, the grid planning process described in the Staff Report does not seem to contemplate the gradual geographic expansion of modern grid capabilities on an as-needed basis. This is a mistake. The largest cost of the flexible grid envisioned by the U.S. Department of Energy – which can help to accommodate high levels of DER and improve reliability/resilience – is in physical field infrastructure. This includes upgrading the capacity of circuits to be used as back-ups, construction of ties between circuits, installation of sectionalizing devices and line sensors, installation of equipment that can be controlled remotely, et cetera. In general, expansion of modern grid capabilities should begin with a limited number of circuits, and be expanded to additional circuits over time only when deemed appropriate (relative to all other grid projects on the table) by the risk-informed project prioritization and selection process.

Overall, Staff seems to perceive DER accommodation as an approaching emergency. This would be an appropriate perspective for Hawaii or California – but not New Hampshire. Until very high levels of DER are reached for a specific circuit, inverter-based DERs (PV solar and batteries) present no threats to grid reliability or significant changes to grid operations. Once foundational capabilities (like back-office software) are established, a surgical approach to expanding DER accommodation to the physical grid *on an as-needed basis* is the right approach. This involves a circuit-by-circuit analysis employing the risk-informed project evaluation and prioritization process referenced *supra*. Failing this, utilities are apt to propose 'across the board' solutions not yet needed. Ratepayers would foot the bill for these improvident expenditures.

Indeed, Staff's focus on standardizing grid architecture leaves the door open to billions in unnecessary grid investment. The grid will always be in various states of development, with a variety of capabilities and technologies. Standardization for the sake of standardization is misplaced. The OCA is concerned that utilities will assume that inconsistencies in existing infrastructure must be eliminated – an excuse to justify replacing hundreds of millions of dollars in equipment that is working perfectly well.

The “Suggested Process” for “Traceability” depicted in Figure 2-6 at page 30 of the Staff Report is missing some critical considerations. According to the text accompanying this figure, “[u]tilities tasked with developing an IDP based on clear objectives can trace the logical path from objective to required functionality and evaluate further actions needed to meet the capabilities required.” But this leaves critical questions unanswered: First, from whose perspective is an objective, functionality, or capability “required”? Second, against what standard is a solution evaluated? Ratepayers and/or stakeholders should make these determinations (as noted *supra*, through the risk-informed project evaluation and prioritization process). Utilities are not hesitant to spend capital to make grid operators’ jobs easier, or to guard against inflated risks, or to comply with artificially high “standards,” so a critical regulatory task – one that requires stakeholder involvement – is to scrutinize these investments and not simply assume they are justified because they are “traceable.” As discussed elsewhere in this letter, the answer to these uncertainties is to establish the IDP framework via an adjudicated proceeding, to be commenced in the immediate future.

VI. Cost Effectiveness Framework

According to Staff, a cost-effectiveness framework, including “common business case assumptions,” should be “developed collectively before they file their first IDP.” *Id.* at 72. Staff outlines a proposed approach elsewhere in its report. *See id.* at 45-48. This task is too critical to be left to the utilities in the first instance and, moreover, the approach recommended to the utilities by Staff is significantly flawed. As suggested in the OCA’s comments on the Grid Modernization working group report, establishing a uniform benefit-cost framework prior to the filing of any requests for grid modernization investments will ensure the even application of costs and benefits among utilities and reduce benefit-costs analysis which are developed only after a utility has prejudged which investments are in its best interest.[12]

Likewise, relying on a “least-cost/best-fit” cost effectiveness test, which Staff recommends for expenditures intended to improve reliability, address resiliency, and facilitate the integration of DERs, is a questionable strategy at best. Benefits that are claimed by utilities but characterized as difficult to quantify are generally vague, highly variable, and, indeed, most often simply a figment of utility executive imagination.[13] If grid modernization is to remain faithful to least-

[12] In New York, Rhode Island, California, and elsewhere, regulators oversaw the development of a specific cost-effectiveness framework that identified in detail the inputs and assumptions the utilities should use *prior* to utility development of a grid modernization plan. *See, e.g*, Order Establishing a Benefit-Cost Analysis Framework (New York Public Service Commission, . Docket No. 14-M-0101, January 21, 2016), *and* Order Accepting Stakeholder Report, Rhode Island PUC, Order No. 22,851 (Docket No. 4600, July 31, 2017), available at: http://www.ripuc.org/eventsactions/docket/4600-NGrid-Ord22851_7-31-17.pdf;

[13] In fairness, precisely the same critique must be leveled at the embrace in the 2017 Working Group Report of a cost-effectiveness test characterized as “a business case framework that includes both a quantitative evaluation and a qualitative evaluation of each program or type of investment.” Grid Mod Working Group Report at 11. The OCA repeatedly raised concerns about this formulation at meetings of the Working Group in 2016 and 2017, for precisely the same reasons we object to the “least-cost/best-fit” approach here. That the “business case” cost-benefit framework is not specifically identified as a non-consensus item in the Working Group Report can be attributed to aggressive facilitation and ongoing pressure (ironic, in light of the subsequent history of this docket) to produce a

cost integrated resource planning principles, as required by RSA 378:38, :39, and :40, the benefit cost framework for investments should focus on the quantifiable benefits and costs that will accrue to New Hampshire's ratepayers.

This is not an insurmountable obstacle for investments whose cost effectiveness is not instantly obvious. All significant sources of benefit can be estimated. Economic benefits available from improved reliability and resilience can be quantified using the DOE's Interruption Cost Estimator, for example. Even non-quantifiable benefits, such as an increase in a circuit's DER hosting capacity, can be scored as part of a risk-informed project evaluation and prioritization process.

The cost effectiveness framework should (1) be based on present rather than nominal values, (2) reflect all carrying charges (i.e. the revenue requirement) customers will be required to pay (e.g., authorized return, taxes on profits, interest expenses, property taxes, etc.), (3) be calculated using a benefit period that matches the depreciation period (measured in years), and (4) include the book value of stranded assets, i.e. assets removed from service to make way for proposed utility investments (including the present value of all depreciation and carrying charges customers will be forced to pay on such assets).

When benefits vary dramatically by customer class, traditional approaches to cost allocation by customer class should be eschewed. The economic benefits of investments designed to improve reliability and resilience, for example, accrue overwhelmingly to commercial and industrial customers. DOE research and the agency's online Interruption Cost Estimate calculator indicate that only 2 percent of the economic benefits from investments designed to improve reliability and resilience accrue to residential customers. This is a critical issue for residential utility customers; the era in which utilities can simply wave the "reliability" banner without regard to the value of the actual and quantifiable benefits of reliability must end.

VII. Targeted Cost Recovery Mechanism

Staff recommends the adoption of a "targeted cost recovery mechanism" to encourage utilities to invest in their grids. Staff Report at 64. This is a euphemism for what amounts to yet another exercise in single-issue ratemaking – a practice that always benefits utility investors at the expense of customers.

At the March technical session, it appeared that Staff was advocating for a cost recovery mechanism that is not just temporally limited (to five years, as noted at page 64 of the Staff Report) but is also tied to (unspecified) performance metrics. This is obviously preferable to unconditional cost recovery, but it is still not sufficient to assure that ratepayers do not bear unreasonable costs. Essentially, there is a grave risk that utilities will shift to the grid mod

report on schedule. As such, this is an example of why ongoing reliance on working groups and other informal stakeholder engagement processes is inappropriate and legally suspect given the importance of the issues under review, as discussed previously. In any event, the OCA is not bound by the conclusions and recommendations in the Working Group Report and we reserve the right to take positions here that are inconsistent with Working Group recommendations.

'tracker' costs that ought to be recovered via regular distribution rates and subjected to plenary review for prudence, used-and-usefulness, etc. in the context of a full rate case. Furthermore, the embrace of any grid mod tracker should also ensure that any operations and maintenance benefits that have been used to justify capital investments begin accruing to ratepayers as soon as they are realized by the utility, rather than accruing to the utility in the near term, and then to ratepayers only once a utility files its next rate case.[14] A single risk-informed project evaluation and prioritization process should apply to *all* electric utility investments – and, to the extent utilities carve out certain investments as related to grid modernization the quid pro quo ought to be stakeholder participation in the process.

VIII. Rate Design

Two years ago, the Grid Modernization Working Group included in its report a set of principles that "should guide rate design in New Hampshire." Grid Mod Working Group Report at 13. The Working Group also discussed several rate design problems that arise whenever an electric utilities allowed revenues are under discussion – fixed customer charges v. volumetric charges, reliance on demand charges, and time-varying rates. *Id*. at 14-15. The Working Group expressed no view about when or where these principles should be applied in furtherance of grid modernization, however.

Laudably, the Staff Report endorses the Working Group's perspective on rate design, Staff Report at 49, but then Staff urges a step with which the OCA is unable to agree. Specifically, Staff recommends that utilities should "consider rate design . . . when developing the distribution system plan" so as to further the objectives of grid modernization.

Rate design is indeed something for the utilities to consider in the context of least-cost planning, but RSA 378:39 (governing Commission evaluation of plans) does not contemplate that LCIRP proceedings will provide the appropriate forum for the adoption of specific rate design proposals. For decisional purposes, rate design questions belong in rate cases.

Staff implicitly acknowledges as much via its very welcome endorsement of revenue decoupling "in the next rate case to remove potential disincentives in grid modernization investments." Staff Report at 63. We agree with Staff that severing the link between utility kWh sales and utility revenue, if done in a fair and symmetrical fashion, liberates utility managers from the throughput incentive as they strive to maximize shareholder return, and thereby reduces if not eliminates a reason to spurn grid modernization initiatives that tend to empower consumers. According to Staff, "[t]he utilities have agreed to revenue decoupling in the next rate case" in connection with the settlement agreement in Docket No. DE 17-136 (implementing the state's Energy Efficiency Resource Standard (EERS) as of January 1, 2018).

Regrettably, this is not entirely accurate. It was actually in Docket No. DE 15-137 – the proceeding in which the Commission approved the EERS in *concept* – that electric and natural gas utilities made their commitment related to revenue decoupling. They agreed only "to seek

[14] One example of this would be advanced metering infrastructure that negates the need for drive-by meter-reading and the associated trucks, FTEs, and other operating expenses.

approval of a decoupling or other lost-revenue recovery mechanism . . . in their first distribution rate cases after the first EERS triennium" – i.e., after December 31, 2020. Order No. 25,932 (Aug. 2, 2016) in Docket No. DE 15-137 at 60. Given that both Eversource and Liberty have formally placed the Commission on notice of their intent to seek rate increases in 2019, it may well be a very long time before this obligation to propose a new lost revenue recovery mechanism is triggered. Nevertheless, the OCA strongly believes that rate cases are the appropriate forum for resolution of issues related to lost-revenue recovery – a perspective, by the way, the OCA is likely to bring to bear on the two imminent electric rate proceedings.

Finally, if the Commission is unable to resist the call for a grid mod tracker we urge the agency to make clear there will be no such recovery mechanism until the requesting utility has fully implemented revenue decoupling. Cost trackers eliminate the earning attrition pressures that normally cause utilities to file rate cases. If the Commission were to approve such a tracker in the case of grid modernization, it would significantly affect the likelihood of a rate cases from the various utilities until the end of the proposed five-year period. Since the current lost revenue framework allows the utilities to collect lost revenues on a cumulative basis between rate cases, this would significantly increase the amount of lost revenues a utility will collect as a result of energy efficiency investments, net metering, and likely grid modernization investments that reduce usage or demand. Such lost revenues could be an order of magnitude higher than those previously contemplated by settling parties and would likely have a substantial impact on customer rates.

IX. Advanced Meter Functionality and Customer Data

The Office of the Consumer Advocate essentially concurs with Staff's perspective on Advanced Meter Functionality (AMF). According to Staff, those utilities with existing AMF should "consider taking full advantage of its capabilities" whereas utilities that lack AMF (here, essentially a synonym for "Eversource and Liberty") "should offer interval metering (at the customer's expense, if implemented on an opt-in basis) in the short term and only fully embrace advanced metering when a cost-effective case can be made." Staff Report at 74.

Our consultants believe that opt-in AMF will not deliver benefits in excess of costs for residential customers in light of the high-cost of necessary back-office upgrades and the likelihood of low participation. Even meter replacements or upgrades paid for by receiving customers and/or third parties are unlikely to be economically feasible given high equipment and installation costs. Traditional demand response programs (e.g., cycling of air conditioning and water heaters, programmable remotely controlled thermostats) may be the right way to obtain the peak reduction benefits of smart meters without the cost of smart meters.

The cost-effectiveness analysis is likely to be somewhat different when time-varying rates (TVRs) are added to the picture. But even assuming TVRs are adopted on an opt-out basis and include a peak-time rebate or critical peak price component, the stranded costs associated with early retirement of existing AMR meters[15] are likely to render AMF an uneconomical proposition from a ratepayer perspective. Of course this assumes no meter-related prudence disallowances in the rate cases that Eversource and Liberty have each recently commenced by filing formal notices with the Commission.

In any event, deployment of AMF as a matter of statewide policy is not something to consider unless and until stakeholders are comfortable with default (i.e., opt-out) TVRs that are designed to reduce peak demand. Using AMF data to settle energy and capacity charges assessed to competitive suppliers should also be a mandatory part of any AMF deployment. Charging competitive suppliers for the burdens their customers place on the system is certain to spur energy management innovations among competitive suppliers, as it has in ERCOT (i.e., most of Texas).

No utility-specific data access system ever developed anywhere offers the ubiquity, and access to smart phone apps and other third party tools designed for mass application, of the Green Button Connect-My-Data (CMD) standard developed under the aegis of the U.S. Department of Energy. No AMF deployment should occur without requiring CMD standard compliance. Failure to require CMD compliance would mean New Hampshire customers lack access to third party tools available to electric customers in states that *do* require CMD compliance (a growing list that includes California, Colorado, Illinois, New York, and Texas). As the Commission and most readers of this letter are already aware, at the request of the OCA the General Court is currently considering Senate Bill 284, which would require the development of a CMD-compliant statewide utility customer data platform accessible to customers and third parties. The Senate has already adopted this legislation and we are optimistic about its ultimate fate. Obviously, we believe strongly that such an initiative plays a critical role in grid modernization; nothing in current law precludes such a project from moving forward.

X. Performance Metrics and Incentives

As already noted, we commend Staff for its embrace at the recent technical session of performance metrics as an important component of IDPs and grid modernization generally. But it is not enough to endorse the concept of performance metrics; they must be correctly designed. Performance metrics adopted as a part of grid modernization should be limited in number (no more than 10 or 12, and ideally as few as five or six. They should measure outcomes, not processes. Assuming *arguendo* that performance incentives for shareholders are in the public interest as a part of grid modernization planning, any such incentives should be (1) consequential (i.e., material in size relative to a utility's rate of return), (2) symmetrical, i.e., including both penalties for poor performance and incentives for strong performance, and (3) subject to relative

[15] AMR is an abbreviation for Automated Meter Reading and, as noted by Staff, AMR meters are those that "collect simple time-of-use or non-interval kWh data for billing purposes only and transmit this data one way, usually from the customer to the distribution utility." Staff Report at 81. Eversource undertook a wholesale AMR meter deployment effort in 2014 and 2015, Grid Mod Working Group report at 40, Liberty likewise converted the bulk of its customers to AMR meters in 2002, whereas Unitil deployed AMI meters (i.e., those with advanced meter functionality) throughout its system in 2007, *id.* at 39. As of the time of the Grid Mod Working Group Report, the remaining average expected life remaining in Eversource's AMR meters was 18 to 23 years; the comparable figure for Liberty was 6 to 18. *Id.* at 40.

weighting among metrics, consistent with ratepayer priorities. Performance targets for metrics should be quantifiable rather than subjective, should include specific dates, should rely on pre-deployment baselines, and should also consider the performance of equitably "like" utilities as distinct from merely measuring changes from the historical performance of individual utilities. Reporting should be public, auditable, and submitted with the endorsing signature of a utility executive.

We do not believe that performance metrics, particularly those tied to incentives, should be 'siloed.' In other words, each utility should be subject to a single, unified set of performance metrics that do not distinguish between "grid mod" performance and so-called "business as usual" (BAU) performance. For example, the Rhode Island Division of Public Utilities and Carriers successfully argued for the merger of Narraganset Electric's "Power Sector Transformation" (i.e.- grid modernization) case and its ongoing rate case because considering investments and performance metrics in a siloed manner, outside of a rate case, would have been more detrimental than beneficial to the ratepayers of Rhode Island.[16] We will make this point, as necessary, in the upcoming Eversource and Liberty rate cases. Any proposed grid project, be it "BAU" or modern, should specify the improvement in a metric the project is estimated to deliver, with targets adjusted in a manner consistent with utility estimates for approved projects.

Finally, there should be consistency between objectives and metrics. Staff lists nine objectives of grid modernization on page 67 of the Staff Report. There should be at least one metric for every objective, regardless of whether what appears on page 67 is the definitive list.

XI. Adjudicate Now!

In light of the legal and due process concerns expressed supra, as well as the policy issues discussed in this letter, we believe it is appropriate to articulate a potential alternative here to the proposed next steps outlined by the Staff. *See* Staff Report at 77. We share Staff's interest in moving forward expeditiously at long last, but believe the appropriate course of action is for the Commission to commence an adjudicative proceeding now, whose purpose would be to address in specific terms how the LCIRP process will become the IDP process (and specify which issues will not be cabined off as "grid modernization" and will instead remain within the rate case realm). A straw proposal for such a proceeding would be as follows:

Early May 2019	Commission issues Order of Notice
Mid-May 2019	Prehearing Conference
May-June 2019	Rolling discovery

[16] *See* Testimony of Timothy Wolf in Rhode Island PUC Docket Nos. 4770 and 4780 (**DATE**) at 13 ("It is not in the interest of ratepayers to consider the underlying rate of return separately from a suite of proposed performance incentive mechanisms"), available at: http://www.ripuc.org/eventsactions/docket/4770-DIV-Woolf_4-6-18.pdf; and Testimony of TimothyWoolf and Melissa Whited at 16 ("since PIMs provide an alternative source of shareholder revenues, regulators can establish the authorized ROE at the lower end of the cost of equity range to reflect those additional revenues that will increase profits. In our view, this is one of the most effective ways to modify the regulatory model to provide a utility the incentives it needs to achieve power sector transformation objectives").

July 2019	All parties submit Prefiled Direct Testimony
August 2019	Discovery on Direct Testimony
September 2019	Rebuttal Testimony
October 2019	Discovery on Rebuttal Testimony
November 2019	Settlement Conferences
December 2019	Hearings
January 2019	Commission Order
May 2020	Utilities file initial IDPs in individual adjudicative dockets
Late 2020	Commission approves IDPs

This schedule is somewhat more ambitious than one that would apply in a rate case – or the one that did apply in the Commission's 2016-2017 net metering proceeding (DE 16-576). We believe this is appropriate given that, as was obvious from the recent technical session, most if not all parties have already done much of the necessary work to take and support positions on how to conduct the IDP process.

Legalities aside, the "adjudicate now" approach is better than Staff's proposed "working group" pathway to IDP submission because nothing guarantees that the latter approach will produce consensus or even clarity. Moreover, eschewing administrative litigation until IDP submission in 2020 creates the significant risk that appellate issues will overturn the entire apple cart in late 2020 or even 2021 – a highly undesirable outcome given that the grid is already modernizing.

XII. Conclusion

On behalf of the residential customers who will foot the lion's share of the bill for whatever investments the utilities make and whatever operating costs they incur in furtherance of their role as the monopoly operators of the state's electric distribution grid, we endorse the proposed reliance on the least-cost integrated resource planning process enshrined in RSA Chapter 378 as the logical and appropriate home for planning the modernization of the grid. But, just as the LCIRP statute assumes that the process of reviewing LCIRPs is separate from rate proceedings, see RSA 378:40 (generally requiring an approved LCIRP prior to rate changes), we urge the Commission to reject the notion that the proposed IDP process is an occasion for single issue ratemaking and rate design.

Additionally, the public interest requires ongoing stakeholder involvement in the process of developing Integrated Distribution Plans. "We're the utility and you're not" may have been an sufferable construct for the old-fashioned LCIRP era in which the Commission and the public could reasonably expect utilities to plan internally, subject only to subsequent verification via the LCIRP approval process that the results were truly least-cost. But it is not acceptable in the Twenty-First Century given that evolving technologies and regulatory structures demand that each electric utility collaborate with customers and third parties.

At the same time, grid modernization cannot become an excuse for the utilities to avoid their longstanding obligations as the holders of monopoly franchises. At least two of the grid modernization "general objectives and attributes" of grid modernization identified in the Staff Report (the first being improving reliability, resiliency and operational efficiency; the second being reducing generation, transmission and distribution costs, *see* Staff Report at 34) are longstanding "business as usual" obligations of the utilities. They must not shirk these duties nor extract additional cost recovery for meeting them.

New Hampshire's electricity grid is well overdue for modernization. We look forward to actively participating in the process of transitioning the Granite State to an electric distribution system for the Twenty-First Century, and we believe the approach we have outlined here is the correct path. Thank you for considering our views.

Sincerely,

D. Maurice Kreis
Consumer Advocate

cc: Service List