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 Save Energy
 Energy Resources Organization
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 Campaign
 State Bank
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 Environmental Foundation
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From: Michael Breish
 Policy Associate
 NW Energy Coalition

May 17, 2018

To: Washington Utilities and Transportation Commission
 Mr. Steven V. King
 Executive Director and Secretary

Re: Docket No. U-161024: Electric Distribution Planning Draft Rules

The NW Energy Coalition (Coalition) appreciates the opportunity to provide written comments on the Washington's Utilities and Transportation Commission's (UTC) electric distribution planning draft rules (draft rules) found in Docket No. U-161024 as well as responses to a list of questions provided by UTC Staff. The draft rules and questions contemplate Staff's proposal and consideration of requirements for investor-owned utilities (IOU) to draft, seek input on and ultimately submit a distribution system plan (DSP) as part of the IOUs' regular integrated resource plans (IRP). The Coalition extends its gratitude for all the work Staff has invested so far and the efforts to include stakeholders in a multi-faceted and complex process.

The Coalition is a 37-year old non-profit organization whose approximate 100 members are composed of environmental, civic, and human service organizations; progressive utilities, and businesses that are located in Oregon, Washington, Idaho, Montana and British Columbia. The Coalition and its members advocate a clean and affordable energy future for the region based on:

- Meeting all new energy demand with energy efficiency and new renewable resources;
- Full and fair accounting for the environmental effects of energy decisions;
- Protecting and restoring the fish and wildlife of the Columbia River Basin;
- Consumer and low-income protection; and
- Informed public involvement.

The new structures contemplated by the draft rules for utility distribution system approaches are urgently needed. At a minimum, the

final rules should bring transparency to a process that, to date, has been tucked away in voluminous and dense utility dockets like rate cases.

There are numerous important connections between traditional resource planning and distribution system planning that need to be clearly understood by stakeholders and the Commission when assessing each part of the system. They must be evaluated and considered in conjunction with one another rather than separately. By transferring the existing distribution system work into the IRP process, stakeholders can more effectively provide input into and the Commission can provide better direction to the increasingly imperative analysis and investment that compromises utility DSP efforts.

Ultimately, the rules should lead not only to transparency, but also more rigorous and thorough analysis that leads to better decision-making. Yet, efforts to renovate the DSP process for utilities should not result in dramatic and excessive changes that could result in deleterious effects to utility operations or ratepayers, such as unnecessary investments in risky technologies that drive up costs for ratepayers or interfere with utility balancing responsibilities. Balance and flexibility underscore what the Coalition ultimately is advocating for at this critical juncture in revising utility planning.

Given the likely amount of exploration and analysis of the new information that will result from utility DSPs, coupled with the amount of infrastructure investment still needed in utilities' distribution systems, the UTC, utilities and stakeholders will benefit from a firm and moderate advance in DSP policy at this time. Once sufficient data are collected, methodologies established and a healthy portfolio of pilots is underway, the UTC may consider what the next phase of DSP is, either through existing processes or potentially new rules or laws.

The Coalition's comments are structured as follows:

1. Overarching principles for DSP
2. Responses to Staff questions
3. Proposed redlines to draft rules

Overarching Principles for DSP

An important component of any planning process, especially one that is newly introduced, is guiding principles or goals. Because the proposed DSP will be part of the broader IRP process, the new plan and any proposed outcomes will be subject to the goal of lowest reasonable cost and risk portfolio solutions. Though that foundational, guiding principle is an essential target under existing utility regulatory paradigms, additional, DSP-specific goals are needed in order to produce a process and plans that are consistent across multiple iterations, rapidly changing technologies and policy landscapes. Furthermore, any policy framework should allow the DSP to evolve in ways that reflect the utility's system and needs as well as new technologies and markets. The DSP must be flexible enough for utilities to be innovative and responsive while also reliably contributing to the utility's broader long-term system planning.

The Coalition encourages the Commission to formally adopt goals in the order accompanying the final rules. As utilities iterate their DSPs and investments, the Commission may

find updating the DSP goals necessary to capture new values or technologies. The Coalition recommends the following initial goals:¹

1. Optimize system demand and generation²
2. Improve the distribution system's reliability, resiliency, and efficiency³
3. Animate distributed energy and demand-side management resources' value through the provision of grid benefits⁴
4. Efficiently and effectively integrate distributed energy resources⁵
5. Utilize methodologies that maximize value streams
6. Leverage customer contributions
7. Equitably and appropriately distribute costs and benefits across ratepayers⁶
8. Ensure transparency, accessibility and security of utility system and customer data
9. Implement and enforce expansive consumer protection measures

Furthermore, the different system, climate, and customer characteristics of each IOU will result in initial DSPs that commence in different spots along a grid modernization timeline. With guiding goals and principles, different starting positions for each utility shouldn't pose a problem as each utility identifies different investments and pathways to achieve similar goals. Not only should goals provide some consistency across utilities and time, but also enable the Commission and Staff to point to acknowledged Commission priorities when evaluating a utility's DSP to ensure adherence to plan requirements.

In addition to specific goals, the Coalition believes that an essential, overarching principle that must be incorporated as part of the rule adoption is the encouragement of a strong, interdependent relationship between the utilities' IRPs and DSPs. Over the long-term, the Coalition envisions these two processes merging in both form and theme into "utility system planning." The proposed draft rules require the utilities to explain "how identified resource investments will be reflected in the utility's integrated resource plan." Greater cohesion and integration of the two processes needs to be encouraged and more explicit in either rules or Commission order. Ideas include:

1. An IRP's action plan identifying where a DSP's action plan satisfies an identified need;
2. Consistency across models, assumptions, methodologies and variables used in both plans;
3. IRP portfolios, sensitivities and scenarios that evaluate different DSP investments and vice versa; and
4. Discussion by the utility of how the processes can be further synchronized.

¹ These goals are informed in part by other states' distribution system investment or modernization goals summarized in the U.S. Department of Energy's Grid Modernization Laboratory Consortium's 2017 State Engagement in Electric Distribution System Planning published in December, 2017, see http://eta-publications.lbl.gov/sites/default/files/state_engagement_in_dsp_final_rev2.pdf as well as Oregon's Smart Grid Goals Reports, see <http://apps.puc.state.or.us/orders/2012ords/12-158.pdf>. In the ensuing footnotes, the Coalition identifies the pertinent goals from some of these states.

² Massachusetts: "Optimizing demand, which includes reducing system and customer costs."

³ Oregon: "Enhance the reliability, safety, security, quality, and efficiency of the transmission and distribution network;" New York: "System reliability and resiliency;" Hawaii: "Maintaining reliable energy service in a rapidly changing system operating environment."

⁴ California: "Animate opportunities for DERs to realize benefits through the provision of grid services;" New York: "Market animation and leverage of customer contributions."

⁵ Massachusetts: "Integrating distributed resources;" Oregon: "Enhance the ability to develop renewable resources and distributed generation."

⁶ Hawaii: "Lower, more stable electric bills;" New York: "System-wide efficiency;" Oregon: "Enhance customer service and lower cost of utility operation."

The Coalition is pleased to see that the Commission is taking the next steps in modernizing utility planning and system operations. All stakeholders must recognize this is one of the first steps of many towards a future where the utilities are more comprehensively planning for and maintaining their entire system.

Responses to Staff Questions

1. *Should the Commission propose parallel natural gas distribution planning rule language, similar to the draft rules in WAC 480-100-238 for electric utilities, with the exception of subsection (3)(c) "Distributed energy resource integration"?*

Yes.

a. *How should distribution system planning rule requirements for WAC 480-90-238 be similar to that of the electric utilities?*

The requirements as proposed, falling under the "short-term capital investment" and "long-term planning and system improvement" components should apply to natural gas utilities as well. With DSP goals that are service and technology agnostic, the provided DSP requirements can apply to both types of utilities without separate designation.

b. *How should the requirements be different?*

The rules should accommodate the types of load that natural gas utilities must ultimately be required to plan for, e.g., firm versus interruptible sales and transportation under certain planning conditions, like peak day. Though parallels might exist regarding how electric IOUs plan for large customers supplying their own generation and relying on the utility for delivery, flexibility is needed for gas utilities in order to accommodate the different types of gas services they provide their customers.

2. *In the draft rule, electric utilities would be required to form a separate advisory group to assist the utility as it develops its distribution system plan, in addition to the usual IRP advisory group. Regarding the distribution system advisory group:*

a. *Should the distribution system advisory group be required, or should it be optional?*

The distribution system advisory group should be required because it would provide beneficial opportunities to engage the public, provide a greater range of opinions, educate impacted stakeholders, and ultimately provide a consistent level of transparency and access to material, analyses, and process decisions. Most importantly, customer-oriented projects, like distributed solar or demand response, are crucial elements of any DSP; therefore, customers and organizations that are involved in these projects must be a much larger part of any DSP process compared to other utility advisory groups. Without an advisory group, the Commission will not be guaranteed that the utilities are fully examining the range of benefits, costs and trade-offs associated with distributed energy resources.

The Coalition finds that the proposed draft rules are sufficient with the establishment of an advisory group for both IRPs and DSPs. However, the Coalition recommends that advisory group specifics, such as protocol, membership, and roles should be delineated in Commission order for two reasons:

1. To allow existing and future IRP advisory groups as well as future DSP advisory groups to recommend enforceable changes to the Commission for consideration and possible adoption, and

2. Enable the advisory group's role and abilities to evolve with the rapidly changing nature of distribution system technologies and markets as well as the utilities' responsibility in managing and executing the DSP.

b. What should be the extent and scope of the distribution system advisory group?

The extent and scope should model that of the IRP advisory group, i.e., the distribution system advisory group should be involved from the conceptualization stage of the DSP to the submission of the final version of the DSP. The utility should also provide space and time for the distribution advisory group to provide feedback about the process, outcome and desired changes for future participation that is formally provided to the Commission in submitting the final DSP.

The scope of the distribution system advisory group should be to ensure the DSP satisfies all binding requirements set forth by the Commission; is responsive to stakeholder input and concern; ensure that all assumptions, inputs, methodologies, and materials used by the utility in developing its DSP are reasonable; and that the direction and actions guiding the utility's DSP reflects both ratepayer needs, market developments and DSP goals and objectives.

The Coalition believes the last point is the most pertinent for Staff to consider due to the customer-centered nature of distribution system investments as opposed to the investments contemplated by traditional centralized resource planning. Meaningful and responsive dialogue should underscore the scope of the advisory group, requiring the utilities to prioritize customer problems and solutions. Ultimately, the scope of the advisory group must reflect the new ways in which customers can proactively be part of utility solutions.

As mentioned above, the Coalition encourages the Commission to consider memorializing the responsibilities of the advisory group, such as extent and scope, in Commission order. Doing so would enable the group to evolve in response to the changing nature of distribution system technologies and planning. The proposed rule language pertaining to the distribution system advisory group should remain flexible. The Coalition believes an additional line allowing periodic revision of advisory group functions, the ways in which the utilities incorporate the advisory group into the planning process and other specifics through Commission order is warranted.

c. Should the advisory group review the modeling methods, inputs, economic assumptions, cost estimates, and other factors that affect the selection of best options, or just review the results of transmission and distribution analysis?

The advisory group should review as much information as necessary in order to provide informative and effective opinions that have material impact on the development and outcome of the report. Any report that ultimately influences how ratepayer monies are spent should be informed by a diverse set of voices that have equal access to information.

Today's energy systems, especially with the integration of distributed energy resources, can operate at a wide range of technical and geographic scales. Unlike centralized thermal generation resources, distributed renewable energy resources are highly variable in space and

time, even within a small geographic area. Therefore, models that are appropriate for analyzing highly centralized, top-down power systems, may now be insufficient to model the integration of decentralized, bottom-up energy resources. New value streams, like locational value and resiliency will need to be implemented in a fair and judicious manner, which the advisory group would be well-suited to provide input on. The advisory group should review the modeling methods, inputs, economic assumptions, cost estimates, and other factors in order to provide fully informed advice.

d. Is the draft description of the distribution planning advisory group's membership appropriate?

The Coalition is concerned by the qualifier "other interested parties who have demonstrated subject matter expertise in distribution system planning or distributed energy resources." The Coalition's understanding of the IRP advisory group is that no similar experience requirement on potential participants is required. To introduce such a qualifier on the distribution system advisory group raises concern.

To ensure that both the distribution system advisory group operates in a constructive and efficient manner while also providing tangible public access to all materials, notes and discussions that are used at or transpire as a result of advisory group meetings, the Coalition recommends that the draft rule language be modified to require utilities to make publically available all advisory group products and related materials. Additionally, utilities should ensure that the IRP advisory group and the IRP itself clearly and exhaustively reflect the work of the distribution system advisory group in order to alleviate any concern that might arise about the aforementioned membership qualifier.

e. Is a distribution advisory group necessary for the natural gas utilities? If yes, what should be the extent and scope of the advisory group?

Yes and the extent and scope should mirror that of the electric distribution system advisory group. Please see the Coalition's response under part "b" of this question.

3. The draft rule uses a new term, "major distribution capital investment," which is not tightly defined by a dollar value or otherwise. This definition is intended to provide separation of routine traditional maintenance of poles and other components from more significant capital expenditures that often have the potential for more than one solution. In those cases, a major distribution capital investment would call for analysis of all potential distributed energy resource options that satisfy the identified distribution need.

a. Would it be useful to include a dollar limit in the definition of "Major distribution capital investment"? For instance, the rule could state a cutoff using an estimated capital cost of over \$1 million. Are there other, better, criteria that the Commission should consider?

The definition proposed in the draft rules is preferable to setting a static threshold mostly because the Coalition believes the proposed definition affords the flexibility and attention to investment context that will be essential in producing outcomes that deliver the most value to the system and customers. The Coalition is concerned that a static threshold could prevent necessary scrutiny of investments that fall under the limit yet have viable and beneficial alternatives. Value streams of projects may have social, economic, or environmental benefits that cannot be easily monetized or do not work favorably with traditional cost-effective methodologies.

If the majority of stakeholders support a financial threshold, the Coalition recommends that a more granular analysis of historical distribution system investments occur so that threshold assigned is less arbitrary. For example, the utilities could segregate investments into various classes and within each class determine a median investment value that serves as investment threshold.

b. *Is there a need to define a major distribution capital investment for natural gas utilities? If yes, should the criteria be the same as for electric utilities? How should it be different?*

The definition proposed in the draft rules suffices for the natural gas utility DSPs as well. The Coalition supports a more granular analysis discussed in part “a” of this question in case the Commission supports a static cutoff in rules.

4. *Distributed energy resources include a broad suite of evolving technologies. Electric utilities are learning through experience and experimentation how to efficiently integrate and value these resources. In recognition of this changing landscape, the Commission wants to encourage significant and creative progress in the prudent adoption and implementation of distributed resources without being too prescriptive in rule. Given that context:*

a. *Is there a recommended structure for organizing the distribution system plan that allows future flexibility as well as engendering significant near-term progress?*

Although a DSP structure should not be too prescriptive, key elements need to be addressed in any decision making and planning process. The Coalition believes a DSP should aim to answer the following:

- What does the current distribution system look like in terms of its configuration?
- How does the system operate?
- Is the system working well?
- How might the system be altered to improve in established criteria or goals, what is the impact of these changes, and should these changes be implemented?

The Coalition offers two broad frameworks for the Commission to consider. First, the Geodesign Framework may be particularly useful. Geodesign was originally developed by Carl Steinitz in 1994 to organize questions about landscape design problems. Within Geodesign, there are six levels of inquiry: 1) representation models, 2) process models, 3) evaluation models, 4) change models, 5) impact models, and 6) decision models. Each model (level or phase are interchangeable terms) is associated with a certain amount of information gain that is usually needed to solve complex problems, such as energy systems design. Geodesign is particularly suited for studying spatial and temporal scales of distributed energy systems because it is a flexible and adaptable approach that can fit a variety of decision problems.

Second, the Commission should consider a structure similar to that used by Portland General Electric (PGE) in its recent Oregon Smart Grid Reports. As a result of an internal organizational process meant to bridge gaps in disparate utility planning and implementation groups, PGE developed a comprehensive approach to “integrating and deploying smart grid technologies.”⁷ PGE uses a “three-staged iterative approach that will enable PGE to build an integrated grid that delivers value to all customers.”⁸

⁷ PGE’s 2017 Smart Grid Report, Docket No. UM 1657, May 31, 2017.

⁸ Ibid., at page 8.

1. Model & Monitor (Plan Ahead)
2. Engage (Successfully Pilot)
3. Integrate (Move to Scale)

This approach is most visible in PGE's Smart Grid Roadmap, which is composed of three sections wherein the iterative approach is applied to identified projects:

1. **Foundational:** Hardware and software that enable deployment of smart grid initiatives, allow customers to realize maximum value of smart grid initiatives, and improve cybersecurity.⁹
2. **Grid optimization:** transmission, substation, and distribution system investments in hardware, software, technologies, and processes that improve system reliability and efficiency, increase flexibility of grid integration, enhance the ability to reduce peak demand, and reduce overall utility operation costs.¹⁰
3. **Customer engagement:** investments in pricing, demand response, and distributed energy resources programs that make customers active participants in the provisioning of energy services, while improving the customer experience, saving energy, enhancing reliability, and reducing peak demand.¹¹

What's particularly valuable about PGE's Smart Grid process is that it allows for the utility to create a pathway consisting of pilots, studies and reporting that leads to an identified outcome that reflects the Oregon Commission's Smart Grid goals. The separate but interdependent sections allow for more efficient and effective exploration of various smart grid technologies that target system or organizational deficiencies. Ultimately, the structure that PGE uses enables relatively faster deployment of pilots, which the Coalition believes will be a critical feature of any Washington utility DSP.

The Coalition finds that either of these two frameworks would provide a sufficient first model for Washington. They are inherently iterative and adaptable to Washington's IOUs, and either would provide the flexibility and near-term progress requested by Staff. Stakeholders must recognize that trial and error will be expected as the utilities move further into transforming their DSP processes and should encourage the utilities to be open to modification. Ultimately, any framework needs to evaluate future scenarios and their associated trade-offs in a methodological manner that is replicable and easily communicated to various stakeholders.

b. Is there specific language that would optimize the combined goals of flexibility and timely implementation?

As a result of the Coalition's work in other jurisdictions evaluating grid modernization efforts, the possibility that utilities get stuck in a perpetual state of designing and implementing pilots without ever moving to full scale is very real and problematic. To ensure flexibility and timely implementation of projects, utilities should be encouraged to implement pilots that have the following criteria:

1. Clearly stated objectives and deliverables;
2. Sufficient budgets with exhaustive narratives about specific

⁹ Ibid., at page 10.

¹⁰ Ibid., at page 11.

¹¹ Ibid., at page 12.

- expenditures;
3. Explicit timelines with clear milestones;
 4. Outcome pathways, e.g., failure to accomplish objectives results in pilot modification or successful implementation results in full-scale deployment.

Though all these criteria are important, a clear and actionable pathway to full-scale deployment is essential so that flexible pilots accomplish timely implementation of distribution system solutions. Including such language in rules must also be accompanied by Commission recourse to compel utilities to additional action, such as denial of a DSP, IRP or potential financial measures. Otherwise benefits readily available to ratepayers may be unnecessarily delayed.

c. How should pilot and demonstration projects be encouraged in rule?

Pilot and demonstration projects should be explicitly authorized and encouraged in rules as part of a utility's proposed DSP. Utilities should be provided assurance that they can receive rate recovery if pilots are sufficiently explained and matched with a DSP goal or objective. Additionally, the advisory group should be allowed to work collaboratively with the utility on pilot identification, design and implementation, particularly if those meet community needs.

d. What criteria should the utility use to evaluate when there is a need for a pilot or demonstration project as opposed to programs ready for full-scale implementation?

Rather than prescribe firm criteria in rules that could discourage utilities from being innovative in assessing distribution system solutions or prevent utilities from deploying projects under rigid circumstances, the Coalition encourages the Commission to adopt a more flexible, contextual approach to pilot proposals. Doing so should enable utilities, stakeholders and customers to develop creative proposals that are able to utilize technology, markets and policies that might be vastly different from the contemporary analogues that exist today.

In considering whether to pursue a specific project for an identified need, the utility should at a minimum consider these questions when developing a narrative as part of its proposal to the advisory group and Commission:

- What is the market status of the project being proposed? Is it still in the research phase, has it been in the market only a few years, or is it well-established?
- Have utilities used this technology before? What other utility experience, both locally and nationally, can be referenced? Do these utilities have similar system characteristics to the utility proposing the pilot?
- Does the utility have operational experience with this technology?
- What kind of system investments would be needed in order to accommodate full-scale deployment of the technology the pilot is testing?
- Do alternative solutions exist to the problems the pilot is designed to address?
- Does the pilot align with a broader DSP goal or objective?
- What obstacles would customers face in engaging with the technology under consideration in the pilot?

5. Recognizing that utilities are at various stages of modernizing their distribution systems, should the rule identify specific assumed fundamental requirements for enabling a modernized grid, such as:

- a. a two-way distribution communication system,*

- b. a distribution management system (DMS) that provides centralized and automated *monitoring and control of the utility's distribution system*,
- c. a distributed energy resources management system (DERMS) that aggregates, *monitors and controls distributed energy resources as dispatchable resources, or*,
- d. other physical infrastructure and software needed to manage and control a *modernized grid*?

Rules should avoid being prescriptive regarding particular types of technology or capabilities, especially considering the degree to which distribution system technologies, the customer need driving them, and even the regulatory paradigms that govern utilities are evolving. Rather, the Coalition encourages the Commission to adopt broader characteristics of a modernized grid that capture customer or system outcomes such as:

- Demand optimization
- System reliability, resiliency, safety, security
- Technology interoperability
- Low, stable rates
- Efficient and transparent utility operations
- System benefits are distributed equitably

Grid modernization characteristics that incorporate these desired outcomes don't preclude technologies like those Staff identified in questions and enable utilities now, in the near-term and the long-term to assess all available solutions that meet system and customer needs at the time of evaluation. A future scenario where centralizing technologies are unnecessary because balancing, triaging, monitoring and other grid services happen on a localized level is very possible. To require the utility to plan for a specific service or role, especially those that are technology dependent, seems imprudent and raises concerns for unnecessary research and stranded assets.

The Coalition strongly encourages the Commission to consider incorporating "interoperability," "system transparency" and "equitable benefits" into whatever final form it adopts in response to this question. These three characteristics are essential to ensuring ratepayers are protected and that reasonable, competitive opportunities exist for distribution system innovation from actors other than the utility.

e. Are the fundamental requirements the same for electric and natural gas utilities? If no, what fundamental requirements should be used for natural gas utilities?

Because the Coalition believes that the Commission should incorporate overarching, comprehensive goals for utilities, both electric and natural gas, that are technology agnostic, the fundamental requirements should not differ for the type of utility. The characteristics identified in the Coalition's response to the other part of this question are fundamental to both natural gas and electric utility system operations and customer considerations.

6. When utilities submit biennial energy conservation reports to the Commission, they are required to provide an independent third-party evaluation of their conservation program achievements (See WAC 480-109-120(4)(b)(v)). Should a similar periodic independent review and evaluation of distribution plan results be required? If not, please explain why this should not apply.

Independent review and evaluation of utility DSPs should occur periodically. Specifically, the greatest need for independent evaluation is on individual investment decisions to ensure that the utility is achieving optimal cost-benefit results, assumptions are reasonable and reflect

actual market characteristics, and that opportunities for competitive procurement processes are pursued for best investments.

7. Should the distribution plan conclude with an action plan? If so, what should be the time horizon for the action plan?

Yes, the DSP should conclude with an action plan. The action plan should be no more than five years to allow for necessary time for pilot design, implementation, possible modification, data analysis and reporting. Furthermore, the DSP action plan should be clearly reflected in the utility's IRP action plan in addition to its role in the IRP overall as the draft rules contemplate. The Coalition also strongly supports rules indicating that the action plan is a binding component of any utility's DSP and that failure to complete actions or provide reasonable explanations to why part or all of an action plan could not be completed may result in punitive action by the Commission.

8. For the organization of WAC 480-100-238, would it provide greater clarity to reorganize the rule into smaller sections, maintain the same organization and numbering structure, or add a new rule section?

The rules pertaining to the DSP should be added to a new rule section in anticipation of evolving DSP scope, role and incorporation into overall utility operations and regulation.

Proposed redlines to draft rules

WAC 480-100-238 Draft Rules for Distribution System Planning (Apr.2018)

WAC 480-100-238 Integrated resource planning. (1) Purpose. Each electric utility regulated by the commission has the responsibility to identify and meet ~~its system demands~~system needs with ~~a least~~the lowest reasonable cost mix of ~~energy supply resources and~~ conservation, generation, distributed energy resources, and infrastructure investments. In furtherance of that responsibility, each electric utility must develop an ~~integrated resource plan that cohesively plans for meeting resource needs through investments in the generation, transmission, and distribution systems.~~ This cross-functional planning approach will assist in identifying and developing: (1) new energy generation; (2) conservation and efficiency resources; (3) methods, commercially available technologies, and facilities for integrating renewable and distributed energy resources, including addressing any overgeneration event; and (4) related infrastructure to meet the state's energy needs.

2. Draft Distribution Definitions. (Expected changes and additions to other definitions will be available for public comment in Summer 2018.)

"Advisory group" means a public group composed of commission staff and other interested parties that is consulted in public meetings convened by the utility at regular intervals during the planning process. A utility may convene separate advisory groups for integrated resource planning and distribution system planning, where the distribution planning advisory group is composed of a subset of members of the integrated resource planning advisory group and other interested parties who have demonstrated subject matter expertise in distribution system planning or distributed energy resources.

"Demand response" means a program designed to meet capacity needs by targeted reductions in customer usage during periods of high demand.

"Distributed energy resource" means any device that is connected to the distribution system or is hosted by a retail customer that can generate electricity, reduce electric demand, manage the level or timing of electricity consumption, or provide ancillary and other grid services, including but not limited to conservation, demand response, distributed generation, electric vehicles, and energy storage.

"Distribution system" means the infrastructure needed to reduce electric voltage and deliver power to retail customers,

Commented [MB1]: The Coalition recommends two additions to the definition of advisory group:

- 1) The Commission through Order shall delineate specific advisory group functions as well as prescribe ways in which the utility should formally engage with the advisory group through the distribution system plan process.
- 2) The utility shall ensure that all materials, notes and information made available to the advisory group are also available to the public.

Commented [MB2]: The Coalition is concerned that the definition of "distributed energy resource" is too limiting. It's current construction does not explicitly allow for software or customer actions, such as utility DER management software or time-of-use rates. The Coalition believes these are critical investments that need to be considered along hardware solutions.

Edits include replacing "device" with "service" or "technology" or adding language that makes explicit demand-side management projects like time-of-use rates, behavioral pricing, and software are considered distributed energy resources as well.

including but not limited to substations, power lines, poles, capacitors, transformers, switches, controls, meters, communication devices, and associated hardware and software. For the purposes of this section, it also includes transmission system infrastructure that is not directly interconnected to another utility and has not been identified for regional cost allocation.

Commented [MB3]: By mentioning software here but using “device” in the definition of “distributed energy resource” creates inconsistencies about what type of technologies and solutions are considered appropriate in a DSP. The definitions should be as broad as possible to encourage innovation as well as flexibility for long-term utility planning and future technology developments.

“Distribution system plan” means a plan identifying necessary investments to improve or maintain the reliability of the distribution system, evaluating potential cost-effective opportunities to defer or displace major capital investments on the distribution system, developing and refining the analytical tools to improve distribution system modeling, and facilitating the integration of distributed energy resources.

Commented [MB4]: The Coalition recommends deleting the term reliability, simply letting the operative actions be “improve or maintain.” Commission-adopted goals in order can better direct utilities to certain system characteristics, such as “reliability,” “resiliency” or “efficiency.”

“Integrated resource plan” ~~or “plan”~~ means a plan describing the mix of energy supply resources and, conservation, and infrastructure investments that will meet current and future needs at the lowest reasonable cost to the utility and its ratepayers.

“Major distribution capital investment” means a distribution system infrastructure investment that is significant enough in scope and cost for there to be opportunities for

distributed energy resources to meet the same need that the infrastructure investment is designed to meet.

(3) **Distribution system plans.** As part of its integrated resource plan, an electric utility must develop a distribution system plan that consists of a short term plan identifying planned capital investments, a long term plan identifying how the utility is improving distribution system operations and transparency, and a report identifying potential tools and practices to facilitate the integration of distributed energy resources. The distribution system plan must serve as an input to the integrated resource plan by identifying distribution system investments that may be leveraged to meet system needs, and by identifying points on the distribution system where the utility may be able to deploy distributed energy resources to meet system generation needs identified in the integrated resource plan.

(a) **Short term capital investment.** A distribution system plan must present a ten year investment plan by:

(i) Identifying locations on the distribution system that have an anticipated need for a major distribution capital investment within the next ten years, with consideration given at minimum to circuits identified in the utility's reliability report,

areas with above-average projected load growth, areas with high present or expected penetration of distributed energy resources, and facilities that are near the end of their expected useful life;

(ii) Analyzing all commercially available resource options that can meet the needs identified at each location, including infrastructure upgrades and distributed energy resources, with all cost assumptions transparently presented;

(iii) Identifying the type and timing of the resource(s) that will meet the needs identified at each location at the lowest reasonable cost; and

(iv) Explaining how identified resource investments will be reflected in the utility's integrated resource plan.

(b) Long term planning and system improvement. A distribution system plan must discuss the utility's efforts to improve the visibility and transparency of distribution system planning and operations. Utilities must develop the necessary infrastructure and tools to readily recognize distribution system needs and identify their optimal solutions, with infrastructure and distributed energy resource investments being considered on equal footing, by:

Commented [MB5]: The Coalition recommends the language be "all cost and benefit assumptions..."

(i) Identifying areas of the distribution system where the utility does not have the level of operational data, monitoring or control necessary to identify locational needs and analyze resource options;

(ii) Proposing monitoring and control upgrades needed to obtain the required operational data;

(iii) Proposing metering and related upgrades that will enable customers to modify their energy usage in response to signals from the utility through programs such as time of use rates and demand response;

(iv) Providing a business case that identifies how the proposed monitoring and metering investments in subsections (ii) and (iii) will be leveraged for the benefit of customers;

(v) Describing advisory group participation in the preparation of the distribution system plan; and

(vi) Identifying planning and procedural improvements that the utility will implement in future planning cycles.

(c) **Distributed energy resource integration.** A distribution plan must facilitate the integration of distributed energy resources by:

(i) Preparing a probabilistic forecast of customer-owned distributed energy resources on the utility's system;

(ii) Identifying potential tariffs and rate designs to both compensate customers for the value of their distributed energy resources and provide accurate price signals for the acquisition and utilization of those resources;

(iii) Identifying opportunities for pilot programs that will enable the utility to better understand and leverage developing technologies; and

(iv) Discussing the utility's efforts to address cybersecurity and data privacy issues posed by the expansion of distributed energy resources.

(4) **Draft rules for procedural changes in subsections 4 through 6 will be available for public comment in Summer 2018.**

Commented [MB6]: The Coalition recommends additional language be added to this part to ensure that cost-shifting to non-participating customers is kept to a minimum.

