# Docket UE-110667 – Study of the Potential for Distributed Energy in Washington
## Selected questions and responses for July 25 work session

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<tr><td colspan="2">A4. Are there changes in state statutes or rules that would encourage technology-neutral development of distributed energy generally, such as changes to financial incentives? For example,<br><br>o Would current interconnection standards need to be changed to accommodate more distributed energy or to accommodate different distributed energy technologies? Why?</td></tr>
<tr><td>Interstate Renewable Energy Council (IREC)</td><td>Third-party ownership<br>Regulatory change to allow 3rd-party owners of DG to operate in WA:<ul><li>The Commission can act on its own to clarify that a 3rd-party owner is not an electrical company subject to UTC oversight (through a declaratory order or a rulemaking); or,</li><li>Legislature could exempt 3rd-party owners from electrical company status and UTC oversight</li></ul>Benefits of allowing 3rd-party DG ownership:<ul><li>3rd-party owners can take advantage of 30% federal tax credit and accelerated depreciation</li><li>Non-profit facilities, schools, and government facilities do not pay federal taxes, but 3rd-party owners that can use these benefits may pass through lower costs to these customers</li></ul>Net-Metering<ul><li>Increase the eligible system cap through legislation to at least 2 MW, or eliminate size restrictions for systems designed not to exceed on-site load</li><li>Increase program participation limits – WA's current net-metering cap of 0.25% of utility peak demand should be increased beyond the 0.5% cap scheduled to begin in 2014 to 5% of utility peak demand or greater of current levels (not 1996 levels)</li><li>Maintain UTC and local regulatory discretion to set the program cap higher – UTC should raise the cap for IOUs</li></ul>Changes to current interconnection standards<ul><li>Legislature could provide statewide uniformity for the interconnection process for IOUs, COUs, co-ops, and municipalities.</li><li>UTC could lower costs of interconnection by:<ul><li>1) prohibiting requirements for external disconnect switches for inverter-based systems, which IREC states are redundant, unnecessary, and add significantly to overall project costs;<ul><li>UTC could pursue a rulemaking to remove the external disconnect switch requirement</li><li>UTC could encourage legislation to remove the requirement.</li></ul></li><li>2) prohibiting requirements for additional insurance to cover liability</li><li>3) adopting FERC "Fast Track" technical screens for generators of 2 MW or less<ul><li>Or, modify the screen that limits aggregated generation on a distribution circuit to 15% of the line section annual peak load; instead base screen on 50% of minimum load (during the hours of 10 am and 3 pm being explored by California utilities)</li></ul></li></ul></li></ul></td></tr>
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| | ▪ Require utilities to make the available capacity of distribution facilities at the circuit level publicly available to help generators identify suitable points of interconnection |
| Avista | [For examples of existing financial incentives for renewable DG, see Comments of Avista, p. 5]<br>*Financial Incentives*<br>• Financial incentives in the form of utility-based subsidies may be costly enough when they are designed to lower the cost of distributed generation to match a utility's avoided cost of acquiring a generation resource<br>• Even more significant cost-shifts would occur from utility-based subsidies that are intended to reduce the cost of distributed generation to the level of a utility's cost of service.<br>• A feed-in tariff may be the most costly form of utility-based subsidy in that it conceptually requires the utility to pay a rate which guarantees that the developer/generator will not only recover all of its investment in a resource that may not otherwise be cost-effective, but also a profit.<br>*Interconnection*<br>• Changing current interconnection standards to accommodate (presumably) larger generation resources risks intruding on the jurisdiction of the Federal Energy Regulatory Commission (FERC), in the event those interconnection standards affect facilities involved the transmission of electricity in interstate commerce. They might also mean that greater costs could be borne by other utility customers.<br>• As a general rule, use of interconnection standards as a method of subsidizing distributed generation should be avoided. |
| Pugest Sound Energy (PSE) | Financial incentives need to be targeted at specific technologies. In general, if they are technology neutral, the investment dollars tend to flow almost exclusively to where the returns are most lucrative. In general the interconnection standards were written for safety and reliability. One possible change is to investigate whether the requirement in WAC 296-45-335 for a visible disconnect switch could be removed for systems that are UL 1741 protected. |
| Pacific Power (PacifiCorp) | No changes are required to accommodate more distributed energy. PacifiCorp believes that the net metering and interconnection rules in Washington are flexible enough to allow the interconnection of distributed energy resources and properly allocate the expenses related to interconnection between the customer generator and the utility. |
| Cascade Community Wind Company (CCWC) | *5 MW Limit on Distributed Generation*<br>The state's current definition limiting distributed generation to 5 MW is reasonable, though a higher limit could be used. It is essential, however, that non distributed projects are prevented from calling themselves distributed by stretching or bending a definition. In both Oregon and Idaho commercial wind farms have split themselves up into multiple 10 MW pieces to qualify for distributed generation incentives. Policies in other states give regulators discretion to disqualify projects that are obviously gaming the system.<br>*Avoided Cost Rate for Distributed Renewables*<br>Puget Sound Energy, through their Schedule 91 avoided cost rate, provided a market for our power at a fair price. Other utilities in Washington do not currently offer an avoided cost rate for distributed renewables. |

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| | *Financial Incentives*<br>Federal Incentives were changed with the Recovery Act to be a simple refundable Investment tax credit anyone could take, a change from the production tax credit which could only be taken against passive corporate income. This was critical for allowing regular people to develop renewable energy. The Washington Production incentive currently has little or no impact on community wind projects at this point. The incentive should be changed from a $5k cap per project to the same $5k cap per participant incentive that community solar projects enjoy, rather than simply raising the cap.<br>*Permitting*<br>Kittitas County provided a process to install our two 100 kW wind turbines, yet they have no process for a farmer to install a larger turbine. Other counties we work in have similar difficulty understanding and providing a permitting path for distributed wind. This issue is critical to the distributed wind energy industry. |
| US DOE Clean Energy Application Center (NW CEAC) | *Changes to RCW 19.285*<br>• Definitions of "bioenergy" in RCW 19.285.030(18) exclude high solids digesters (food processors and compost facilities) block at least 20 MW to technical market potential. Food waste and green waste should be added to the list of renewable energy.<br>• RCW 19.285.030(13) regarding "nonpower attributes" should be limited to electrical generation. The shutdown of dairy manure lagoons is a methane reduction pathway for sale of greenhouse gases.<br>• Spent liquor should be added to the list of renewable energy. See RCW 19.285.030(18).<br>*Net Metering*<br>• Limit should be increased to 2 MW similar to Oregon OPUC action. |
| eFormative Options | *Wind Resources*<br>• Washington has a lower incentive level than California, Oregon, and other states; WA is missing out on reaping substantial economic benefit<br>• Upfront payments are important in aiding consumer financing. A supplement to the state's existing performance-based incentive (PBI) could create a hybrid approach to issue partial payments upon construction based on estimated production using certified power curves and wind map calculations. Such a program can be expensive to administer, which could reduce the amount of funds available for incentives.<br>• Scaling incentives based on AWEA Rated Power, wind map ratings and tower height could be a simpler approach to encourage proper siting. Reducing incentives gradually over time can also aide the market in reducing costs for consumers.<br>• Requiring that small wind turbines are certified by an independent certification organization such as the Small Wind Certification Council (SWCC) in order to qualify for incentives is extremely important for several reasons.<br>    o It maintains the integrity of the industry<br>    o Provides the state with some certainty of turbine performance, so rate refunding is used prudently. Prompt deadlines need to be set for requiring certification to ensure manufacturers prioritize and complete testing in a timely manner.<br>    o Through the end of 2011, incentives should be limited to turbine models with power performance tests conforming to AWEA 9.1 – 2009 that have been verified by the SWCC. |

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| Northwest Energy Coalition and Renewable Northwest Project (NWEC) | • Varying costs and scale of the DG technologies in question must be considered. Also, the meaning of "neutral" policy must be specifically defined. If the attempt is to encourage the least-cost technologies, then a single incentive level is appropriate. On its face, this incentive would be "neutral" by not identifying a single technology that it encourages, but in reality this incentive would promote only the technology or technologies that are made economically viable by the given incentive level. If the attempt is to encourage similar amounts of development of multiple technologies, then the incentive program must be structured based on technology and size-specific costs. Due to the multiple benefits associated with energy resource diversity, including complimentary resource profiles and increased grid stability and security, a DG incentive that encourages the development of multiple renewable technologies is preferable to one that encourages a single technology.<br>• The incentive level is more important in determining the extent of an incentive program's neutrality, while the mechanism by which the incentive is delivered is less deterministic (e.g. cost-based incentive or production-based incentive). For example, distributed wind, solar, and biomass can and do function in incentive programs based on production (e.g. Federal Production Tax Credit, Washington Renewable Energy System Cost Recovery Program, or Oregon Solar Feed-in Tariff), cost (e.g. Federal Investment Tax Credit (ITC), Federal ITC Grant, or Oregon Residential/Business Energy Tax Credit), or a combination of both.<br>• Although both production and cost-based incentives have been effective in encouraging renewable energy development in the US, the feed-in tariff (FIT) mechanism (i.e. production based incentive) has proven to be highly effective in incenting distributed solar PV across the globe. However, a FIT program does not need to focus on solar PV alone.<br>• 3rd-party ownership of DG systems should be incorporated into any DG incentive program |
| Local Energy Alliance of Washington (WALEA) | Yes, regulatory changes are needed to facilitate the deployment of distributed energy projects.<br>• Current *interconnection standards* should be changed so that the cost, process, and timeline for interconnecting a distributed generation system is substantially similar to the process for connecting a similar sized load to the utility's system. All such systems would obviously have additional standardized protective relays and disconnect switches, but otherwise the process should be no more difficult.<br>• *Avoided Cost Payments*: California, Oregon, and many other states have avoided cost rules that specify that distributed renewable energy projects need to be paid the cost of the most expensive source of energy being used by the utility at any time. Puget Sound Energy has voluntarily created such a rate for distributed projects, Schedule 91. These costs are estimated and projected out into time such that a standard set of prices can be set for a project at interconnection that ensures the project its pricing during the project's financing. These avoided cost payments are and should be structured to be cost neutral to the utilities. This sort of stable fair rate for power is the base that distributed energy projects of all technologies should be able to rely on.<br>• *Community Net Metering*: allow neighbors to share in a single distributed renewable energy system. Similar to avoided cost pricing, Community Net Metering gives distributed generation projects access to the market at no cost to the utility or to the |

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| | taxpayer. WALEA recommends a policy that follows the IREC guidelines quite closely. The 2011 bill HB 1049 in most respects does this. Policy built upon this bill would be a great boon to distributed generation in that it would allow customers to choose to participate in local renewable energy projects, avoiding many NIMBY issues as all the beneficiaries of a project would be local.<br>• A *Feed in Tariff* (FIT) is the most effective mechanism for encouraging distributed generation. Fair market access combined with a well thought out cost recovery incentive could have the same effect of a feed in tariff.<br>Non-Utility Policies:<br>• *Permitting* – SHB 1081 which passed both the House and the Senate in 2011 but could not be reconciled between the two houses was an attempt to correct the lack of siting rules in most counties and cities for distributed generation. Ensuring that appropriate distributed energy projects have a permitting path in all jurisdictions (where appropriate) is a key element to enabling growth of the sector.<br>• *Air Quality* – Combustion based distributed generation such as anaerobic digestion, biomass cogeneration, and even natural gas based district heating deserve lighter regulation by air quality laws than they currently receive. These technologies often reduce emissions (digestion removes a methane and odor source) or replace multiple other sources (district heating replaces multiple unregulated heat sources). State of the art installations should not have a significant air quality compliance burden while there still should be protections against technologies of this scale that don't meet industry standards. |
| Snohomish Public Utility District No. 1 (SnoPUD) | *Financial Incentives*<br>*Local Authority*<br>Establishing financial subsidies at the state level for DG takes away from the local governance and decision-making authority that has been reserved by our ratepayers. Incentives could result in windfall profits to developers at the expense of ratepayers<br>*Consideration for utility resource need*<br>There is a surplus resource at this time; consideration must be given to utilities that have a large number of DG customers wanting to interconnect, but do not have a resource need. This may result in utilities purchasing energy only to resell it at a loss in the wholesale market, resulting in higher electric rates and risk to utility ratepayers.<br>*Interconnection*<br>• Several components of the interconnection process and the agreement between generators and the utility could be standardized, but the type of resource and its point of interconnection would determine whether interconnection would be standard or unique. For example, a 2 MW generator interconnecting at the end of a feeder in a remote area will likely require additional equipment and interconnection facilities, compared to a 200 kW generator located near a major substation.<br>• It is important that utilities be allowed to maintain flexibility to develop their interconnection processes appropriate to each resource and system configuration<br>*Permitting*<br>Permitting and regulation are barriers for wave, tidal, and micro-hydro technologies.<br>• Recommend that agencies and stakeholders first approach the deployment of single devices and small arrays so that until proven otherwise, would have small impact projects with minimal environmental effects |

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| | • Support adaptive management as a solution to confirm initial assessments of low-impact, and monitoring for long-term impacts that are undiscovered |
| King County Department of Natrual Resources and Parks (DNRP) | *Changes to RCW 19.285*<br>• King County's scrubbed gas system at South Treatment Plant was built in 1987 and does not qualify for Renewable Energy Credits (RECs). It is one of only a handful of wastewater gas scrubbing systems in the nation. Qualifying for RECs would improve the economic viability of current or expanded production levels.<br>• Energy captured from sewage in conveyance lines, before it reaches a treatment plant, should also clearly be defined as "renewable" in State legislation. As noted below, 1-937 has left some question as to whether sewage-based energy (through heat recovery or other technologies) will qualify as "renewable" in Washington State. |
| Farm Power Northwest, LLC (FPNW) | *Long-term fixed-price standard contracts*<br>In order to encourage technology-neutral development of distributed energy, state statutes should require investor-owned utilities to offer long-term fixed-price standard contracts at just below projected retail electricity rates to distributed generation projects. Long term means at least fifteen years, rather than the five years currently required. Fixed-price means a forward strip of at least fifteen years, and the price of just below retail is a reinterpretation of "avoided cost" that is far more meaningful than the cost of running a distant utility-scale power plant. A realistic calculation of the avoided cost of electricity delivered to a local feeder by a distributed generation project should be based on the value of that electricity delivered to the next customer on the feeder, minus nominal administrative and balancing costs. |
| Cascade Power Group (CPG) | *Clean Energy Standard Offer Programs and other Feed-in-tariffs*<br>• Utility company rates should sufficiently bridge the gap between the cost of producing renewable energy and improving efficiency of existing systems; and the current cost of producing fossil fuel based energy. The rates should be based on system operational improvements and environmental impact rather than defining a specific type of technology. This is the best way to incentivize innovation and improvements. Clean Energy Standard Offer Programs and other feed-in-tariff incentive payments are based on such, and are an effective way to mitigate $CO_2$ and gain energy improvements locally.<br>*Interconnection Procedures Best Practices:*<br>• Set fees that are proportional to a project's size.<br>• Cover all generators in order to close any state or federal jurisdictional gaps in standards.<br>• Screen applications by degree of complexity and adopt plug-and-play rules for residential-scale systems and expedited procedures for other systems.<br>• Ensure that policies are transparent, uniform, detailed and public.<br>• Prohibit requirements for extraneous devices, such as redundant disconnect switches and relays, and do not require additional insurance.<br>• Apply existing relevant technical standards, such as IEEE 1547 and UL 1741.<br>• Process applications quickly; a determination should occur within a few days.<br>• Reduce costs of system impact study<br>• Standardize and simplify forms. |

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| | *Interconnection Recommendations for WA*:<br>• Prohibit requirements for redundant external disconnect switch<br>• Prohibit requirements for additional insurance |
| **A8. If rates or incentives are established at the state level, would it violate or conflict with the federal law provisions in PURPA and the Federal Power Act? For example, if the Commission interprets PURPA to establish a feed-in tariff at the state level, is the Commission obligated by federal law to establish a rate that does not exceed avoided cost?** | |
| IREC | • In 2010 FERC clarified that earlier precedents denying states' requests to pay generators with specific characteristics a higher rate than a utility's avoided cost do not prevent states from setting separate avoided costs for generators that meet a specific state procurement requirement (e.g. RPS requirements); resources acquired to meet an RPS would justify calculation of avoided costs of other renewable resources rather than from all available resources<br>• In the context of WA's RPS, which includes double credit for eligible DG up to 5 MW, avoided costs could be set at up to double the cost of the least-cost renewable alternative (i.e. utility-scale wind)<br>• Avoided costs derived from a market mechanism may more accurately represent the price necessary to support renewable DG development |
| Avista | Yes. Under section 210 of PURPA, electric utilities are obligated to offer to purchase available electric energy from Qualifying Facilities ("QFs"). The rates for such purchases from QFs must be just and reasonable to the ratepayers of the utility, in the public interest, and must not discriminate against co-generators or small power producers. Rates also must not exceed the incremental cost to the electric utility of alternative electric energy (also known as the electric utility's "avoided costs"). New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities, 114 FERC ¶ 61,043, P 8 (2006); see also 18 C.F.R. § 292.304(a). |
| PSE | Issues regarding preemption and conflicts between federal and state laws are generally fact-specific, and thus, difficult to answer in the abstract. Certain state rates or incentives could be found to violate PURPA or Federal Power Act (FPA) provisions. These issues can be complex. Existing avoided-cost standards must be addressed in state programs in a manner consistent with the intent and requirements of PURPA and the FPA. As a case in point, California adopted a feed-in tariff for combined heat and power under Assembly Bill (AB) 1613 in 2007. California utilities challenged such legislation before the FERC. On October 21, 2010, the Federal Energy Regulatory Commission issued a declaratory order-responding to AB 1613 indicating that states do have the flexibility to implement feed-in-tariffs at the state level, but must do so in a manner consistent with the framework of PURPA's avoided-cost provisions. FERC denied rehearing on January 20, 2011. The California Public Utilities Commission is currently considering further utility petitions for modifications that assert that state policy violates PURPA's avoided costs standard. Bills have also been introduced in the U.S. Congress regarding these issues. Accordingly, specific state programs affecting rates must be reviewed for consistency with federal standards. |
| PacifiCorp | Whether or not rates or incentives established at the state level violate or conflict with federal law will hinge in large part on whether such rates or incentives exceed the utility's avoided cost, as that term is defined by PURPA. FERC has held that certain feed- |

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| | in tariffs and incentive programs are not preempted by the Federal Power Act, PURPA or FERC regulations as long as: 1) the relevant generator is a QF pursuant to PURPA; and 2) the rate or incentive established does not exceed the avoided cost of the purchasing utility. Therefore, under current federal law, the Commission may not establish a rate that exceeds avoided costs. A state program that results in the setting of non-QF wholesale rates or establishes purchase obligations for FERC-jurisdictional entities is likely to be preempted by federal law. |
| NW CEAC | There are several ways to fix PURPA and Power Purchase Agreements in WA. PURPA-based PPAs should be for up to 20 years and up to 10 MW. A number of projects are inhibited by WA's approach to PURPA/PPA implementation (limits as low as 1 MW and for only 5 years). This limited approach impacts development of distributed energy projects in dairies, forest products and food processing facilities. These are projects in the 1 to 10 MW range. One cannot get long term financing on a 5 year PPA. Both the Oregon and Idaho utility commissions have superior approaches. In Oregon, Docket UM 1129 established long-term contracts (up to 20 years) for all Qualifying Facilities (QFs), standard contract forms for QFs up to 10 MW, and standard avoided cost rates for up to 15 years for QFs no larger than 10 MW (with the option of partially fixed rates in years 16-20), among other provisions. In Idaho, baseload CHP systems such as larger dairy digesters sized in the 1 to 4 MW range benefit from the up to 10 MW and up to 15 year PPA ground rules. This is a core problem for distributed generation in WA. It is within the purview of the UTC to make major improvements. |
| NWEC | Taxpayer-funded incentives are not affected by the Federal Power Act or PURPA, whether the incentives are delivered up front, as tax credits, or as production-based incentives akin to a feed-in tariff.<br>These federal laws restrict only incentives that are structured to set rates for sale of electricity to utilities, as classic ratepayer-funded feed-in tariffs do. Authority to set rates for sale of electricity to utilities—normally reserved exclusively to FERC by the Federal Power Act (FPA)—is granted to states pursuant to PURPA. PURPA requires utilities to acquire certain types of generation, including small renewable generation, and allows individual states to set the rate for that electricity at the utility's avoided cost. States cannot set rates for sale of electricity that exceed the utility's avoided cost.<br>However, FERC recently clarified that, when a state legislature has required utilities to procure a specific type of generation, the state can set a special avoided cost unique to that type of generation. *See Cal. Pub. Util. Comm'n,* Order Denying Reh'g, 134 F.E.R.C. ¶ 61,044 (Jan. 20, 2011). For example, if a state law requires utilities to acquire a certain amount of generation from solar facilities, the state is authorized to set a separate avoided cost rate for solar resources.<br>Net-metering is another way to establish a ratepayer-funded production-based incentive while avoiding FPA restrictions. Net-metered power offsets a customer's generation, so is not a sale of electricity to a utility. A bid system, which lets the parties establish the rate, is another way in which the state can avoid setting the rate for sale of electricity; however, sellers may be required to obtain FERC permission. |
| WALEA | Recent rulings in CA show that the UTC has a lot of leeway, especially if the state passes a distributed generation requirement.<br>During rulemaking for Oregon's Solar Pilot Program at the PUC, it was discovered that Section 210 of PURPA prevents states from setting prices that utilities must pay for wholesale renewable energy at above avoided cost. Avoided cost is typically equated to the highly subsidized cost of energy from fossil fuels like natural gas and coal and is much |

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| | lower than the cost of generating electricity from renewables. Only FERC can set wholesale prices for renewable energy. This is known as the “FERC pre-emption”.<br>The program design chosen by the Oregon PUC for the Solar Pilot Program to avoid FERC pre-emption provides a disincentive to maximize solar production. It limits the maximum size of an installation at a given location to less than the customer’s annual consumption and will not pay the fixed rate above avoided cost for production in excess of consumption in order to avoid the possibility of a wholesale sale by the customer to their utility at above avoided cost. This constraint creates a perverse incentive for the customer generator to over-consume energy in order to maximize their production payment, and creates a disincentive to adopt energy efficiency measures.<br>Recommendations:<br>• STATE: Amend statute to include a 100% purchase guarantee.<br>• FEDERAL: In a case brought by California’s PUC, FERC recently ruled that PURPA does allow states to set wholesale prices for RE at above avoided cost, but the case was appealed by CA’s utilities. An amendment to PURPA would fix the problem. Both Senator Wyden and Senator Sanders will introduce amendments this session. Senator Wyden’s PURPA PLUS Act sets a project size cap of 2MW, which is too low and if the FERC decision is not upheld, would prevent the application of FITs to large wind, solar and probably wave nationwide. Twenty other states have FIT bills somewhere in the legislative pipeline and will encounter the same problems Oregon has. We need a fix that works for everyone and frees states to decide what mix of renewable energy technologies and project sizes best fits their needs. |
| CPG | If a state has a renewable requirement under PURPA authority (CPG doesn’t believe any do right now), avoided costs are no longer solely based on the one and only least expensive generation unit. FERC stated that “[If] a state required a utility to purchase 10 percent of its energy needs from renewable resources, then a natural-gas fired unit…would not be relevant to determining avoided costs for that segment of the utility’s energy needs.” In other words, in states that decide to create a new renewables requirement under PURPA, renewable generation can have an avoided cost that is distinct from the general system mix. It is important to note that RPS policies are mandates under state law (not under PURPA), which means the FERC ruling would not apply directly. |
| **A10. If the Commission were to change the avoided cost methodology for certain types of renewable resources, what criteria should we take into account as we do this? Should there be a total cap on the amount of resources to be acquired in this manner, and, if so, state-wide or by utility? Should there be a carve-out for certain technologies that are in a more nascent stage of development now, or should commercially available and emerging technologies be treated equally?** | |
| Avista | To the extent that the UTC changes the avoided cost methodology for certain types of renewable resources, the guiding principle should be to ensure that the avoided cost rate is just and reasonable and does not exceed actual avoided cost. Developers of QFs using certain technologies, most notably wind QFs, have taken advantage of published avoided cost rates by disaggregating large projects into smaller projects. Some states have attempted to adopt certain criteria, such as enhanced separation requirements and ownership restrictions, to prevent such disaggregation. Most recently, the Idaho Public Utilities Commission (“IPUC”) considered adopting factors to prevent disaggregation. Ultimately, the IPUC found that attempting to prevent disaggregation without addressing |

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| | the avoided cost rate was not practical. Order No. 32262 (issued in GNR-E-11-01 on June 8, 2011).<br><br>The Company understands that there is some precedent for imposing a cap. With regard to a carve-out for certain technologies, it is permissible to treat different resources differently under PURPA. See 18 C.F.R. § 292.304(c)(3)(ii) (stating that the published avoided cost rate can differentiate between different technologies). For example, the IPUC recently imposed a different published avoided cost rate eligibility cap for solar and wind resources (100 kW) in order to prevent developers from disaggregating such resources to take advantage of published avoided cost rates. See Order No. 32262 (issued in GNR-E-11-01 on June 8, 2011). That said, the Company believes any such carve out is subject to the requirement that the rate paid by the electric utility is just and reasonable to the ratepayers of the utility, in the public interest, does not discriminate against co-generators or small power producers, and does not exceed the electric utility's avoided costs. |
| PSE | • In general, ratemaking practices and policies that encourage alternative energy supply and their retail deployment should be generously considered. Policies which favor the reduction of reliance on large, environmentally intrusive technology such as conventional nuclear and coal plants and mega hydro projects merit consideration. Such projects have 'long-tail' liability attributes often unable to be measured and reflected in current rates, but will be identified as the useful life of such technology comes to an end. Site remediation, decontamination and decommissioning and de-construction costs of such projects will be material. The intergenerational equity issues of such technologies are not insignificant. Emerging distributed generation technologies may harbor fewer such long term costs and risks and their development and application should not be unduly burdened by conventional least cost assessment standards. At present, there is no apparent need to fix caps or impose other arbitrary limits on distributed generation technology use.<br>• If the UTC were to change the avoided cost methodology for certain types of renewables, PSE would favor a cap by utility and a specific carve out by technology. Washington could learn much from the California experience where a variety of policies and financial incentives exist to foster the development of distributed renewable resources cheaper, better, and faster. |
| PacifiCorp | *[If the Commission were to change the avoided cost methodology for certain types of renewable resources, what criteria should we take into account as we do this?]*<br>• Impact of renewable portfolio standards (RPS), consistent with PURPA and FERC precedent. FERC clarified that the avoided cost rate may not include a "bonus" or "adder" above avoided cost to provide compensation for environmental externalities, although such costs can be included if they are real costs that would be incurred by the utility.<br>• Renewable resource sufficiency/deficiency timing as identified in PacifiCorp's IRP.<br>• Avoided cost should be based on the estimated cost of the next avoidable renewable resource identified in PacifiCorp's IRP preferred portfolio, and these costs should be used at the conclusion of the resource sufficiency period.<br>• Ownership of the environmental attributes (i.e., renewable energy certificates (REC), etc.).<br>• Integration cost of the resource. |

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| | *[Should there be a total cap on the amount of resources to be acquired in this manner, and, if so, state-wide or by utility?]*<br>No. PacifiCorp has an obligation to purchase the net output from PURPA projects regardless of resource type. The acquisition of renewable resources under PURPA is based on IRP resource needs and timing, driven by cost-effectiveness and risk mitigation.<br>*[Should there be a carve-out for certain technologies that are in a more nascent stage of development now, or should commercially available and emerging technologies be treated equally?]*<br>No. PacifiCorp does not support carve-outs for developing technology. PURPA does not allow the utility to discriminate among technology if the technology qualifies as a renewable resource under PURP A. Since QF resources are designated to serve network load, it is prudent for the utility to ensure that the project, regardless of technology, becomes operational to supply customer loads through an upfront review of the project and through contract terms that provide risk mitigation and credit support in the event of default. |
| NWEC | We are not presently in a position to comment on specific approaches to changing the avoided cost methodology for renewable resources. Various parties are analyzing the development of a generic renewable avoided cost in Oregon Public Utility Commission (OPUC) Docket No. 1396, and some principles discussed there may be helpful as the UTC considers this issue.<br>At this stage of developing FERC precedent, technology-specific avoided costs are likely permissible only if state laws require utilities to procure generation from those specific technologies. (See response to Question 8, above.) Under this logic, establishing a carve-out in the state's renewable portfolio standard for specific technologies, such as solar photo voltaics, could provide the basis for a technology specific avoided cost rate. Absent such laws, all renewable technologies would have to be treated equally in setting an avoided cost rate.<br>Finally, the UTC would need to consider what impact a change in the avoided cost methodology would have on the identification of cost-effective conservation. |
| WALEA | • The UTC's job is to ensure consumer protection, part but not all of that is avoided cost resource acquisition. Very real costs and benefits though are not currently included in UTC rate setting. Most notably is the cost/impact of global warming and the dire need to produce much more than 15% of electricity from renewable resources. Another major figure not in the equation are the benefits of local economic development to be gained though distributed energy production. WALEA believes that certain benefits should be incorporated into avoided cost rates that are not currently (resource diversity/capacity, avoided transmission and distribution upgrades, avoided new fossil generation, decreased fuel price risk), these should be wrapped up in an avoided cost structure that gives distributed generators full and fair pricing for all benefits under the authority of the UTC and available to all distributed renewable technologies.<br>• Other benefits should be paid for outside of the rate structure with a system benefit charge, current cost recovery incentive, or another mechanism. These benefits include (greenhouse gas reduction, local economic benefit, job creation, energy security, technology development). These benefits could be compensated in a combination of incentives such as the cost recovery incentive that target desired technologies and modes of implementation but a more flexible method of targeting incentives and maximizing benefit per incentive dollar spent should also be created. |

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| CPG | Avoided cost methodology seems relatively straightforward with the recent FERC rulings on using new natural gas generation as the ‘baseline’ to avoid. Renewable energy ‘backs-out’ fossil generation, which receives a ‘climate credit’ for doing so. Renewable energy avoids two things: fossil fuel generation costs, and environmental remediation costs from that fossil fuel generation. Energy efficiency and conservation should always be the ‘priority’ resources, as it avoids ALL generation whatsoever (“the cheapest MWh is the one we don’t use”).<br>• Yes, there should be carve-out for specific technologies - and it should be based on the “most-benefits” concept explained in the previous answer. Projects that show the highest number or quantity of benefits should be prioritized for project development. Also, technologies that produce thermal AND electric resources should have a higher priority than electric-only or thermal-only ones.<br>• Suggested prioritization list:<br>1. Combined heat and power (energy efficiency)<br>2. Urban-area district energy systems<br>3. Urban-area solar thermal and solar electric<br>4. Urban-area waste to energy (costs are still high)<br>5. Rural renewable energy production<br>6. Rural fossil-fuel energy production |
| **A13. What marginal costs are associated with the interconnection requirements for the connection of distributed energy systems? Are those costs material, and how should the costs be recovered (socialized or born by customer-owners of distributed resources)?** | |
| Avista | The costs associated with interconnecting distributed generation vary with each system. At a minimum the cost is a production meter; at maximum the cost is a dedicated feeder and ancillary equipment to integrate the generation resource. These costs presently are and should continue to be paid for by the customer-owners of distributed resources. |
| PSE | For customer-owned distributed generation, the interconnection costs of UL 1741-protected systems is not material to the customer, typically a few hours of time for a qualified electrician. Under state and federal law, the developer/owner of the system who will benefit from the system pays for the costs of interconnection. Related utility administration costs (such as the five employees helping coordinate net metering programs) are currently paid for by all customers per UTC Order in Docket No. UE-990016. Distributed generation may not save money on the distribution system if the distributed generation has intermittent characteristics and, consequently the distribution system has to be designed to reliably operate when the distributed generation is not generating. |
| PacifiCorp | For PURPA QFs, all interconnection costs are paid for by the interconnection customer. Interconnection costs are all costs associated with interconnection and service of a customer’s on-site generating facility (on the customer’s premises) connected to PacifiCorp’s distribution or transmission system. Interconnection costs include all reasonable costs, charges, and expenses (including all reasonable internal costs and overheads) incurred by PacifiCorp in the design, construction, installation, modification, testing, regulation, approval, inspection and commissioning of the desired interconnection. The total amount of the interconnection costs can vary significantly based on the specifics of the interconnection required for service. |

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| NWEC | There are material costs associated with the interconnection of DG that can vary based on a project's size or specific needs. Typically, the interconnection costs are minimal and the socialization of those costs can be justified by the added benefit brought to the grid by the DG system. If the cost is borne by the customer, an assumed integration cost should be included in the calculation of an appropriate incentive level. IREC has provided multiple solutions in its comments for decreasing the costs of DG interconnection and streamlining the process. |
| WALEA | Direct interconnection costs (line extensions, switch gear, meters, etc.) should be borne by the distributed resource owners, this puts the proper incentive on the developer to plan projects where they most cost effectively integrate with the grid. Costs of making the distribution system ready for distributed generation (direct transfer trip relays, substation metering improvements, billing software upgrades, system switching, etc.) should be socialized as part of a plan to make local generation commonplace, rather than be borne by the first generator to interconnect to a distribution system. |
| DNRP | The marginal costs of an interconnection requirement require labor hours and certain pieces of equipment. This will be a multiplicative cost base on the number of distributed energy facilities that are connected. As this cost is based on the necessity to connect a system for localized use, we believe that it should be borne by customer-owners of the distributed resource. |
| CPG | Protection costs should be borne by the utility company and not the customer or project developer. Interconnection requirements should be relevant to today's energy industry standards and best practices, and should NOT have significant shortcomings that impede the facilitation and deployment of distributed energy resources onto the grid. Many substations and utility feeders do not have the same protection required by customer generators (i.e., dual protection and relays). |
| **A14. Should the current statutory restrictions on the size of distributed energy resources be changed? If so, please explain the reasons for the suggested change.** | |
| Avista | In 2011 an Avista internal distribution system study confirmed the broad conclusions of an earlier 2001 EPRI study. Based on this information, Avista believes that interconnected resources exceeding 5% of light load-hour demand on any distribution feeder should be evaluated on a case-by-case basis, with the resource owner being responsible for any facility upgrades necessary to maintain system reliability. |
| PSE | The definition of what constitutes distributed energy resources merits careful consideration before making changes. If net metering were increased to 300 KW from 100 KW, it would still allow the low-cost interconnection projects. However, this change may not expand the market potential of distributed generation materially since all of the projects in PSE's service territory are typically in the 3-4 KW range, with a few above 20 KW. Accordingly, PSE does not judge the present 100 KW cap to be much of a market limitation. For example, a new school with 350 KW solar is interconnected and utilizing PSE's fixed-offer contract under Schedule 91. A proposed net metering limit greater than 300 KW will encounter more complex and costly issues of safety and power-quality. |
| PacifiCorp | An argument could be made that the net metering cap could be raised to allow larger commercial facilities to participate more fully in net metering. The current cap of 100 kW is one of the lowest among PacifiCorp's six-state service territory. As renewable technologies have become more affordable, the Company has witnessed an increase of larger projects in other states, in many cases initiated by government entities. To date, |

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| | the Company has not been faced with the need to refuse a project due the cap in the Washington service territory. |
| NW CEAC | The net metering law should be raised to 2 MW to benefit commercial and small industrial customers. |
| NWEC | Distributed generation can be defined in terms of connection and location (e.g., generation units installed close to the load or at the customer side of the meter) or in terms of generation capacity (e.g., 1 kW to 20 MW or more). Washington statute does both:<br>▪ The Energy Independence Act (I-937) defines distributed generation as "an eligible renewable resource where the generation facility or any integrated cluster of such facilities has a generating capacity of not more than five megawatts."<br>▪ The Net Metering statute includes certain facilities with "an electrical generating capacity of not more than one hundred kilowatts."<br>▪ The Cost Recovery Incentive Mechanism does not cap the amount of production from a renewable energy system contributing to customer-generated electricity (instead placing a cap on the maximum amount of incentive paid annually to each customer-generator), but does cap a community solar project at 75 kW.<br>▪ The sales and use tax exemptions for machinery and equipment used in generating electricity from renewable energy sets a threshold of at least 1 kW, and a maximum for solar of 10 kW.<br>▪ The Emissions Performance Standard defines distributed generation as "electric generation connected to the distribution level of the transmission and distribution grid, which is usually located at or near the intended place of use." No specific size limit is provided.<br>▪ RCW 35.92.360 and RCW 54.16.280 expand the definition of conservation for municipalities and public utility district financing purposes to include "the on-site installation of a distributed electricity generation system that uses as its fuel solar, wind, geothermal, or hydropower, or other renewable resource that is available on-site and not from a commercial source." Again, no specific size limit is provided.<br><br>For simplicity and clarity, we believe the size threshold associated with distributed generation in I-937 is appropriate, and for consistency, we recommend raising the size of eligible net metering systems to 5 MW. In conjunction with that change, we recommend increasing the cumulative cap for all net-metered systems from the current level of 0.5% of the utility's 1996 peak demand to at least 5%. That modification is critical to ensure the potential for broad participation, and to ensure that larger commercial and industrial systems don't occupy all of the allotted capacity leaving residential systems stranded. We note that several states have placed no limits on the aggregate amount of net-metered systems (e.g., AZ, AK, CO, CT, FL, Iowa, LA, ME, MN, MT, NM, NC, ND, OH, OK, OR for IOUs, PA, WI, WY), an approach we prefer. We also recommend increasing the minimum allocation reserved for net-metered systems powered by renewables from one half of the total allotment to at least three-fourths of the total allotment with an increase in the size of net-metered systems. |
| WALEA | • Distributed generation is of a size that connects to a utilities distribution system, not the transmission system. The current definition of renewable resources 5 MW and under is sufficient and suitable but that number could go slightly higher, perhaps up to 10 MW, and still meet the common sense definition of distributed. For example, Coastal Community Action's 6 MW wind project in Grayland, WA should be |

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| | considered distributed.<br>• The use of 'average MW' or other ways of shoe horning distinctly non distributed projects into this category should be avoided, and those stewarding the policy should be on guard for them.<br>• As far as technology all renewable resources under 5 MW (or whatever the limit is) the current definition is good but eliminates certain types of hydro power (which can actually have the lowest impact per MWh of any technology ironically, but are difficult to implement for other reasons )<br>• A central theme for WALEA is that all renewable resources should be included in distributed generation policy. We recognize that different technologies have different impacts but their impacts should be addressed in legislation addressing the impact rather than excluding that technology from being renewable. |
| CPG | • Yes the cap should be raised to 2MW. The 100kW limit placed on net metering systems is insufficient to incentivize industrial and commercial investment into efficiency technologies such as Combined Heat and Power. Furthermore, it is insufficient to allow institutions such as schools and public agencies to offset their own energy consumption. The purpose of the existing cap on capacity is to prevent excess export of electricity from customer generators onto the grid, but it is also preventing larger load consumers from offsetting their use. A cap of 2MW would be more appropriate, with the recommendation of limiting the customer's energy production to the annual use of the customer (i.e., no export). We also support the recommendation to raise the utility company cap from 0.5% to 5%.<br>• We do not believe the definition of the term "distributed generation" should include projects that directly tie to the transmission grid, and are over 2MW in size. |
| **C1. If the cost of building a distributed energy resource is not yet competitive, and a subsidy is recommended, what form of subsidy is best?** | |
| Avista | A subsidy for distributed generation can be provided through two systemic mechanisms. One requires an interconnecting electric utility to assume costs on behalf of the generator and to recover those costs from its customers; the subsidy entails a cost-shift. A second conduit for a subsidy involves the dedication of public resources to the generator.<br><br>Policies promoting distributed generation have been justified on the basis of their environmental attributes, particularly their role in reducing greenhouse gas emissions. This rationale overlooks the greater efficacy of environmental regulations which have and will continually require electric utilities that generate electricity with fossil-fuels to reduce emissions from their facilities and to acquire more efficient generation technologies over time. More significant and cost-effective emission reductions can be achieved with central station generation than from measures to encourage piece-meal development of distributed generation. Encouragement of distributed generation through a subsidy may not directly achieve significant environmental objectives, especially when compared to the amount of emission reductions achieved through environmental regulations. In other words, policies to advance distributed generation deployment based on environmental reasons have a societal, or "social", underpinning. Subsidies for distributed generation are, in addition, often pursued on the grounds that |

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| | they will spur the creation of new jobs in the installation and manufacturing of distributed generation technologies; this objective is clearly a societal one, the costs of which should be socialized accordingly<br><br>Social policy objectives should be supported with public resources. Utilities should not be used as instrumentalities for conveying a subsidy for distributed generators, especially when those subsidies necessitate that associated costs or risks must be borne by utility customers. Utility customers, as a general proposition, should not subsidize distributed generation unless the value of the subsidy is offset with a commensurate economic benefit, which is a proposition that assumes ratepayers would experience no quantifiable economic impact by the "subsidy". Ensuring that ratepayers would be kept financially indifferent to the existence of a subsidy may be difficult to achieve.<br><br>A preferable subsidy is one that assumes the form of a government administered one that respects the prohibition in Washington State's Constitution on the lending public credit. Such a subsidy could replicate the existing investment cost recovery program; perhaps the amount of the incentive could be increased and/or the scope of the program expanded to apply to larger generators. Another subsidy could be predicated on the current sales and use tax exemptions for machinery and equipment used to generate solar energy; this exemption could be altered to encompass more distributed generation technologies.<br><br>One financial incentive that would not cause a cost-shift to occur among utility customers or necessitate the deployment of public resources is one that encourages utility investment in distributed generation. One such incentive is already embodied in Initiative 937 (Chapter 19.285 RCW). As mentioned earlier, the acquisition of distributed generation or its associated renewable energy credits may be counted by a "qualifying utility" against the Initiative 937's renewable energy standards at double the value of the resource's output. This "multiplier" does not seem to encourage much, if any, acquisition of distributed generation; this would indicate that doubling the value of distributed generation for the purposes of complying with the renewable energy standards may be inadequate to compensate for the higher cost of distributed generation compared to other compliance options. We encourage the Commission to investigate this issue and identify a multiplier that would level the compliance value of distributed generation technologies with that of commercial wind resources. |
| PSE | The best subsidies are ones that are provided directly by the state or federal government and do not burden the shareholders nor the ratepayers of utility companies. The policies should not result in one site or one type of utility having a competitive advantage over other utilities. |
| PacifiCorp [addressing all financial incentives questions 1 – 3] | Washington policymakers are ultimately responsible for determining if and when subsidies for distributed energy resources are desirable. PacifiCorp has observed a variety of different state and federal incentive programs at work across its six-state service territory. The financial cost, design, duration, and applicability of each incentive is a product of many considerations that range from the perceived diversity of energy resources, current electricity costs, electricity market structure, economic development, and overall economic health of the state. PacifiCorp does not have specific recommendations as to the amount or structure of new subsidies for distributed energy resources. However, new subsidies/incentives are an explicit admission that these |

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| | energy resources are not cost effective for customers. Therefore, if Washington policymakers determine that other social, economic, and environmental factors beyond the cost of these resources support subsidies, then the most effective and fair approach is a public subsidy approach (such as Washington's community solar tax credit or the federal renewable energy production tax credit) that advance public policy on a utility customer-neutral basis. Subsidies within and among utility customers are less defensible and fraught with unintended consequences, primarily because of the different ownership structures, rates, customer attributes, geography and business models of individual utilities. |
| CCWC | *Community Net-Metering*<br>CCWC provides a mechanism for community members to subscribe to the output of a community wind turbine. Subscriptions provide us with needed upfront capital and them with green power and power bill savings for the life of the turbine. We believe incentives and policies that empower individuals to pool their resources to construct larger more efficient, well sited, and professionally managed systems are the best way to build a local energy economy. By relying on community support, DG projects have natural limitations to local resource, local desire for said generation, and eliminate many forms of corporate gaming. This also ensures that the economic benefits of these systems stay local and are enjoyed broadly across our communities. Providing for Community Net Metering (also called virtual, neighborhood, or remote net metering) by our utilities would provide a market for distributed generation that was self-limiting to local demand. |
| Washington State Housing Finance Commisison (WA HFC) | The WA HFC believes that the policies and enforcement the UTC establishes for interconnection cost containment, net metering and feed-in tariffs associated with distributed energy systems materially affect their financial feasibility and thus their rate of adoption or development.<br>WA HFC encourages the UTC's efforts to respond to the Legislature's request and call for a comprehensive review and development of State energy incentive and finance programs, taking maximum advantage of existing federal tax, loan guaranty and spending programs for distributed energy and energy efficiency and renewable energy (EERE) retrofits of buildings.<br>Federal programs include:<br>• Renewable Energy Business Investment Tax Credit<br>• Modified Accelerated Cost Recovery System (MACRS)<br>• Rehabilitation Tax Credits<br>• Tax-Exempt and Tax-Advantaged Bonds (including traditional governmental and private activity bonds, as well as Qualified Energy Conservation Bonds (QECBs), and Clean Renewable Energy Bonds (CREBs)<br>• Better Buildings Initiative<br>• Ramp Up to Retrofit awardees (including Seattle)<br>• Weatherization, and<br>• FHA, DOE, USDA Rural Development and SBA loan guaranty authorities<br>UTC and State-level financial incentives, policies, and programs which should be included in a comprehensive review and development of renewable energy and EERE projects include:<br>• Cost containment of interconnection policy, practice, and costs<br>• Feed-in tariffs<br>• Net metering |

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| | • Viable practices for development of an efficient market for RECs in WA benefiting WA renewable energy (RE) and EERE projects<br>• Incentives (utility, ratepayer, State) for RE and EERE projects<br>• Review of State tax policy to remove impediments to RE and EERE projects, and to explore new tax-based incentives for such projects<br>• Review of utility and 3rd-party PPA practices, and exploration of UTC and legislative policies to support cost efficient and feasible use of PPA contracts to support RE and EERE projects<br>• Development and exploration of loan guaranty, utility investment, finance and support for RE and EERE projects<br>UTC should be mindful of the potential for other developing technologies, such as waste heat recovery, that in effect are a hybrid of energy efficiency and renewable energy projects. Many of the issues described above also affect projects such as district or neighborhood level heating or combined heat and power strategies, which have the potential to further reduce pressure on utility-scale electricity generation by capturing and using waste heat or by feeding excess electricity generated by waste heat projects into the grid. Any incentive system must be mindful of other innovative technologies that may be currently in development or may become available in the future. |
| NWEC | The most efficient forms of financial incentives are either an upfront cash incentive or a performance based cash incentive paid out over time. Tax credit incentives are less efficient than cash incentives because of the costs associated with monetizing a tax credit for individuals or organizations without sufficient tax liability to fully utilize the credit (e.g., non-taxpaying entities). Furthermore, participants in either an upfront incentive (UFI) or performance-based incentive (PBI) should be explicitly allowed to assign the incentive to a third-party. The third-party installation and financing model has proven to be a highly popular and effective method for driving the development of DG due to its ability to overcome the upfront capital cost barrier, which is the main hurdle for most potential DG customer-owners. In the case of either a UFI or a PBI, such as a feed-in tariff, the incentive can be funded by ratepayers or by taxpayers. |
| WALEA | For standard subsidies a production-based incentive is best, it puts the obligation on the project owner to maximize output(s) of the generator. For innovation subsidies directed by a mission-oriented nonprofit can be most effective in making sure subsidies are used as wisely as possible in meeting goals not well met by set program rules. The Energy Trust of Oregon is a good example. The State Energy Program ARRA grants are another example of directed financing for innovation. |
| FPNW | The best subsidy for a still-uncompetitive distributed energy resource is a capped cash grant worth no more than 10% of the installation cost of the project. This will mimic the success of the federal “Treasury grant” in stimulating construction without as large of a cost to taxpayers and without the complication of monitoring production in future years |
| CPG | Equipment buy-down programs ($/kW) or production payments (based on environmental benefits) are generally best. For CHP and district energy systems, a CESOP policy or subsidization of capital project costs would help to offset the high initial costs and make projects viable. Federal grants and utility rebates can help to make up the difference in cost. If, between grants and a capital cost buy-down, there is still not an economically viable project - then the project should continue to seek the financial support it needs to become mature. We should not ‘throw money’ at new technologies based on our own ‘opinion’ of their merits. |

| **C3. Should subsidies, incentives or renewable energy credits be paid or created for power generated through distributed resources while market prices are negative?** | |
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| Avista | No, there should not be any subsidies, incentives or renewable energy credits paid or created for power generated through distributed resources while market prices are negative. |
| PSE | In order for incentives to be effective they must be as certain as possible. Given that, to the extent such incentives are paid based on production, they should be paid based on actual production and regardless of market electricity prices. The disposition of subsidies and incentives depends on what the contracts have provided for. The renewable energy credits ("REC" or "RECs") as defined in RCW 19.285.030(17) are created whenever renewable power is generated. The market prices at the time a REC is generated and created is irrelevant. RECs exist independent of the market prices at the time. |
| NWEC | Prices on the energy spot market should not be considered as part of any DG incentive program. In order to encourage investment in DG, certainty surrounding future payments for energy produced is crucial. Furthermore, renewable energy credits (RECs) are automatically created through the tracking of power generation; disallowing REC creation would require curtailing DG systems. A DG incentive program with uncertainty surrounding future payments or possible curtailment would be highly unattractive for potential participants and businesses. |
| WALEA | A stable market and incentive structure is essential for growth of the industry. While distributed generation is still a small percentage of the market it should be protected from fluctuations such as negative market prices. As DG becomes established rules may need to change, but for the near future the impact of providing incentives during brief negative market periods will be negligible compared to the benefit of developing this industry. Feed in tariffs, avoided cost rates, and incentives can be structured to provide low incentive for production during periods likely to have low or negative market prices but the numbers should be preset and predictable. Oregon's avoided cost rate has an off and on peak rate, putting some of this desirability of power during certain times into the structure of their rate. |
| CPG | Yes. A mistruth is that distributed generation of electricity through renewable resources is contributing to negative wholesale electricity prices. We believe that utility-scale (i.e., non-distributed generation) renewable energy projects such as wind power development in rural areas are not distributed generation because they do not offset local demand. Instead they simply feed directly onto the grid in large and intermittent quantities, which directly contributes to negative electricity pricing. The distributed renewable sources designed to offset on-site use should be protected from this market phenomenon while the industry is small and investment still low. Uncertainty in return on investment would be exacerbated by the uncertainty about market prices. Financial incentives for time-of-day or peak period production are less risky. |