Avista Corp.
1411 East Mission P.O. Box 3727
Spokane. Washington 99220-0500
Telephone 509-489-0500
Toll Free 800-727-9170

July 15, 2011

VIA: Electronic Mail

David Danner
Executive Director and Secretary
Washington Utilities & Transportation Commission
1300 S. Evergreen Park Drive S. W.
P.O. Box 47250
Olympia, Washington 98504-7250

Re: Comments of Avista Utilities - Docket No. UE-110667

Dear Mr. Danner,

On June 24, 2011 the Washington Utilities and Transportation Commission (UTC or Commission) issued a "Notice of Work Session and Opportunity to File Written Comments" in the above referenced Docket. The Washington State House of Representatives Technology, Energy and Communications Committee (TEC Committee), and the Commission are conducting a study related to the development of distributed energy in areas served by investor owned electric utilities. Specifically, the TEC Committee has asked the Commission to provide to the Legislature background information and detailed discussion of options to encourage the development of cost-effective distributed energy in areas served by investor-owned utilities, as well as the opportunities and challenges facing investor-owned utilities and their ratepayers in developing distributed energy in this state.

The Commission proposes to address in the study the opportunities and challenges for developing distributed energy by reviewing:

- The current state and federal statutory authority governing distributed energy;
- Issues that apply to all forms of distributed energy, regardless of technology, including interconnection standards, system sizing restrictions, storage, and financial incentives, such as tax incentives, net metering and feed-in tariffs;
- Evaluations of the technical and economic potential for distributed energy, and the challenges and issues in Washington using specific technologies, including, but not limited to solar, hydrokinetic, wind, biomass, and biogas; and
- Policy options and recommendations for developing distributed energy in areas served by investor-owned utilities.

The Company appreciates the opportunity to provide comments on the "Potential for Distributed Energy in Washington State" and looks forward to participating in the upcoming Work Session on July 25, 2011. The Company's response to the Notice is provided below. The Company would like to note at the outset that the questions posed in the Notice do not define "distributed generation"; thus, unless the context warrants otherwise, our answers presume that the term is intended to be understood as it is defined under RCW 19.285.030.

Issues and Questions

A. General – Cross-Cutting Issues:

1. What is the scope of current and anticipated distributed energy in the service territories of Washington's investor-owned utilities, including technology type, size and capacity; distribution across service territory; application of feed-in tariffs or net-metering; and any other relevant information? For each technology, what is its total technical resource potential (in contrast to the present, economically viable potential)? Is it concentrated within the state?

RESPONSE: Avista has the following distributed energy customer installations in the state of Washington:

- 2 Hydro for 3 MW;
- 76 Solar for total generation capacity of 333 kW;
- 14 Wind for capacity of 98 kW; and
- 6 Wind-Solar for capacity of 18 kW.

These installations total 3,449 kW of generation capacity. The Company has approximately 30 new installations annually; this number is expected to remain consistent absent new incentives. Solar generator installations are expected to be the majority of distributed energy installations in the future since wind and hydroelectric sites are limited in Eastern Washington.

2. What is, or what is anticipated to be, the overall cost of integrating distributed energy resources to investor-owned utilities?

   RESPONSE: Costs for larger projects, generally over 100 kW, vary greatly and are dependent on the specific circumstances. The generator is responsible for the interconnection costs. The costs of integrating small distributed energy resources through net metering are mainly associated with Company personnel time and travel resources. Avista inspects, verifies protection, and commissions each installation. The anticipated cost of integrating these small distributed energy projects is approximately $30,000 annually, based on 30 new installations a year. Where the number of installations increases, so will the annual cost. In terms of the hour-to-hour and minute-to-minute operation of Avista's electric system, the amount of distributed energy resources are small at this time and generally do not have an impact on load/resource operations.

3. Describe the incentives paid by or through investor owned utilities. How much is paid annually for each technology?

   RESPONSE: Avista provides state incentive payments under WAC 458-20-273 which authorizes a customer investment cost recovery incentive payment to help offset the costs associated with the purchase and use of renewable energy systems located in Washington State that produce electricity.

4. 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,
   - o Would current interconnection standards need to be changed to accommodate more distributed energy or to accommodate different distributed energy technologies? Why?

   RESPONSE: In order to answer this and other questions posed, it is instructive to inventory incentives that already exist for renewable energy, including distributed generation. Prominent examples of "financial incentives" for renewable energy are: (1) The investment cost recovery program, which is based on a public utility tax credit under Chapter 82.16 RCW; (2) a multiplier that enables qualifying utilities to count distributed generation (defined as being less than 5 megawatts capacity) against the renewable energy standards under RCW 19.285.040; (3) net-metering which allows a customer-generator to offset their generation against their retail electric bill pursuant to Chapter 80.60 RCW; (4) a 75% sales and use tax exemption on the purchase of machinery and equipment (including the value of labor) used to generate electricity from renewable resources capable of generating not less than 1,000 watts of electricity under Chapters 82.08 and 82.12 RCW and available until June 30, 2013; and (5) a full sales and use tax exemption on the purchase of machinery and equipment (including the value of labor) used directly to generate not more than 10 kilowatts of electricity using solar energy until June 30, 2013.

   One of the principal obstacles to broad scale deployment of distributed generation is the relative cost of generating energy with such systems compared to standard electric service offered by an electric utility. The cost differential between distributed generation and the relatively low-cost electric service provided by Washington utilities is more acute here compared to other states. That differential affects acceptance of distributed generation in at least two ways. First of all, a customer may be discouraged from investing in distributed generation because any savings realized from not buying as much, if any, electricity from its serving utility may not accrue enough economic value in a time frame that is attractive to the customer. Second, unless or until the cost of producing energy from distributed generation is at least equal to the cost of utility service, a customer, particularly a residential one, may not perceive any financial advantage in acquiring distributed generation.

The cost impact on utility rates for the magnitude of subsidy that would be necessary to make distributed generation cost competitive with utility service is all the greater in Washington because of the comparatively low cost of electric service offered by the state's utilities. 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. 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. (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.)

Interconnection standards can be defined as a "financial incentive" only when they cause an electric utility to incur costs that are recovered from other customers; in other words, the subsidy for the generation derives from a cost-shift. 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. Subsidies conveyed through interconnection standards may not be sufficient on their own to encourage distributed generation of comparatively small size (a meaningful interconnection subsidy may be more likely to accrue to larger generators, especially those requiring interconnection to transmission facilities). As a general rule, use of interconnection standards as a method of subsidizing distributed generation should be avoided.

5. What storage options exist that could be used to help integrate distributed energy into the electric grid?

   RESPONSE: There are several existing technically available storage options to help integrate distributed energy in the electric grid. These include pumped hydro storage, various types of battery technologies, compressed air storage, flywheels, and customer based storage. With the exception of pumped storage, storage options have not developed to the scale where it can be constructed and operated in an economic manner. Pumped hydro is commercially available but may not be economically viable in the current market conditions.

6. Do distributed energy technologies impact investor-owned utility rates currently? If so, please describe how and whether rate impacts affect certain customer classes more than others. How might future rates be impacted?

   RESPONSE: For Avista Utilities in the State of Washington, distributed energy technology deployment has been limited. The Company currently offers avoided costs rates under Schedule 62, "Small Power Production and Cogeneration" Schedule. The Company does not have any end-use customers selling energy to Avista under that Schedule. The Company also has Schedule 63, "Net Metering," which is applicable to customers with an electrical generating capacity of not more than 100 kilowatts. The Company currently has 96 customers on Schedule 63, providing 449 kW of generating capacity. The level of participation by Avista's customers in distributed energy technologies has not reached any sort of a critical mass, and therefore has not caused a noticeable impact on current rates. As to the future of distributed energy technologies impact on rates, please see the Company's response to question A4 above.

7. Do distributed energy technologies meet winter peaking needs for investor-owned utilities? Can distributed energy technologies serve base load capacity? Which distributed energy technologies serve primarily as an hour-ahead or day-ahead energy supply? How can each of the distributed energy technologies and fuel sources contribute to meeting utility peak load needs?

   RESPONSE: Distributed energy technologies may be able to meet some winter peaking needs and provide base load capacity for investor-owned utilities. Resources such as digesters, landfill gas, and co-generation might meet peak load requirements. Other resources such as solar, wind, wave, and hydrokinetics may not be counted on to meet peak needs, although they may still help meet peak load when generation actually occurs. The amount of peaking, or base load contribution will be entirely based on the number, size, technology and actual operation of the resources that are developed.

8. 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?

   RESPONSE: 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).

9. Certain statutes and Commission rules require the UTC to review resource acquisition pursuant to least-cost planning. Would pursuing distributed energy conflict with those rules due to the nascent state of technology development and current cost to implement? How far, if at all, should the state depart from least-cost planning principles and rules?

   RESPONSE: The high costs and relatively limited nature of these resources would likely prevent distributed generation from being built under least-cost planning guidelines, although these resource types should be considered in an Integrated Resource Planning (IRP) process. Under the current state of the technology and costs of distributed resources, the only way distributed generation is likely to be constructed is as a pilot project, with the aid of significant grant money, or through government mandates. In many other areas of the country distributed resources are being tested. Further testing in Washington will be of little value until other states have completed their projects and potentially helped to drive costs down. The state should not depart from least-cost planning principles and rules as a matter of practice.

10. 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?

    RESPONSE: To the extent that the Commission 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 the avoided cost rate was not practical. Order No. 32262 (issued in GNR-E-11-01 on June 8, 2011).

It is the Company's understanding 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, 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.

11. Other policy incentives, both at the state and federal level, already exist for certain types of renewable resources, such as federal grants and state or federal tax benefits. How should these incentives be considered in to the calculation of avoided cost?

RESPONSE: The avoided cost rate is the incremental cost to the utility of alternative electric energy. Therefore, if the alternative to purchasing the output of a QF is for the utility to develop and own a similar facility, all incentives available to the QF should be considered in setting the avoided cost rate. For example, if a QF produces RECs, the value of those RECs should be considered when establishing the avoided cost rate for such facility because, if the utility were to develop and own a similar facility it would own the RECs associated with that facility.

12. For both capacity and energy, how does the current cost of building distributed energy technology compare with other available resources?

RESPONSE: Avista's 2009 electric IRP reviewed the cost of distributed generation for wind, solar, wave, and hydrokinetics. Each of these resources was found to be more costly than traditional resources and was not selected in Avista's Preferred Resource Strategy. The only distributed generation resources likely to be cost competitive are landfill gas, manure/solid waste digesters and co-generation. The limited numbers of these projects are indicative of the market not being able to support them. No distributed generation resources were successful in any Avista renewable requests for proposals. If the cost of distributed generation becomes cost effective as technology improves and costs decrease as manufacturing scale increases, the market will start to support increased construction of these types of resources by utilities or by third-parties.

13. 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)?

RESPONSE: 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.

14. Should the current statutory restrictions on the size of distributed energy resources be changed? If so, please explain the reasons for the suggested change.

RESPONSE: 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.

15. Can each distributed energy resource be used to support emergency management practices in addition to electricity generation?

    RESPONSE: No. Distributed energy resources do not provide viable support for emergency management practices because the Company does not have control over the distributed energy resource and is therefore unable to operate the facilities in a manner supporting emergency management practices.

16. Are there other technologies we should consider in addition to wind, solar, hydrokinetic, biomass, and biogas? If so, please identify the technology, the state of development and likelihood of adoption.

    RESPONSE: We are not aware of other viable technologies to consider at this time

B. Technology-Specific Issues:

Distributed Solar

1. Not including the photovoltaic solar panels themselves, what is the cost of installation on a unit basis of solar panels in distributed energy applications? How does this compare to the per-unit cost of installation for utility scale applications?

   RESPONSE: Our Company's most recent experience with solar proposals have not included itemizations of the photovoltaic module and other balance of plant costs. Traditionally, an uninstalled module would account for roughly half of the total installed cost. A typical distributed solar system ranges from $4,000 to $6,000 per installed kW. Energy production over 25 years with a capacity factor of 12 to 15% would equate to a $300 to $550/MWh levelized energy cost. Larger multi-MW systems may be in the

$2,000 to $3,000 range with levelized costs in the sub $200/MWh range. It is safe to say that larger photovoltaic systems can generally utilize economies of scale to reduce module, inversion, installation and other ancillary costs. Other factors may have a more pronounced effect on the overall economics of solar installations. Ownership, financing and associated accounting and procedures have a significant effect on project economics. To the extent that a non-utility developer may be able to finance the project through a highly-leveraged debt deal, for example, the total cost of the non-utility project may be less than a utility sponsored project. There are many other variables that would affect the total cost, such as cost and availability of land, cost of the interconnection, etc.

2. Is the integration of the variable output of photovoltaic power production made easier or less expensive if it is distributed versus central plant photovoltaic production?

   RESPONSE: In general, a distributed generation system has the advantage of reducing potential line losses. The natural diversity of distributed systems tends to reduce the effects of localized sky cover and other climatic variations. Smaller net metered systems installed at the customer level require little utility integration other than a production meter and an appropriate interconnect inverter. Typical photovoltaic production profiles tend to coincide with system loads and tend to reinforce local distribution circuits. Larger distributed systems could cause operational issues in cases where feeder loading is light or they are installed at more remote locations. Each distributed system would require separate building approvals, permits, inspections, net metering calculations and utility administration.

3. Are there lessons learned from Oregon's tariff subsidies for solar installations? Is there a calculated subsidy per kWh for the Oregon program?

   RESPONSE: The Company is aware of legislation (House Bill 3039) that was enacted to establish a pilot program, beginning in January 1, 2010, for solar photovoltaic generation of up to 500 kilowatts by retail electric customers and a utility-scale solar mandate requiring electric utilities in Oregon to generate a statewide total of 20 megawatts from solar systems ranging in size from 500 kilowatts to 5 megawatts by January 1, 2020. Furthermore, the Company is cognizant of Oregon's renewable energy tax incentives, offered under its Residential Energy Tax Credit and Business Energy Tax Credit programs, and the fact that these incentives have been revised recently. Nevertheless, as a natural gas supplier only in Oregon, we are not involved enough in all of these programs to offer any insightful comments on them at this time.

4. Given the variety of tax and other financial incentives for solar manufacturers and consumers, are additional incentives needed?

   RESPONSE: While the cost of photovoltaic installation continue to trend down, lower energy costs in the Pacific Northwest make economic justification for solar energy difficult. Washington incentives and Federal tax incentives bring the gap closer, however many end use customers are reluctant to make the initial capital investment for distributed systems. Utility scale solar systems are generally not competitive with wind projects in the Pacific Northwest and therefore are not included in resource planning.

Distributed Wind

5. Is the integration of the variable output of wind power production made easier or less expensive if it is distributed throughout the service area rather than centralized from a utility-scale wind farm?

   RESPONSE: It totally depends on location and size. Both types are possible but can be very detrimental to the utility. For example if there is a large quantity of distributed generation placed on one utility feeder, voltage control on the feeder may be impossible to meet ANSI 84.1 voltage standards and clearances for utility personnel to safely work on the utility system.

In the case of a large central wind generation installation, protection on the utility feeder may be affected and reliability of the feeder can decrease. A large centralized wind farm should be on a dedicated distribution feeder so as to reduce impact on the utility. This would add considerable cost to the installation.

6. What is the estimated contribution of distributed wind generation to meeting a utility's peak demand?

   RESPONSE: Previous Avista Integrated Resource Plans have documented that wind generation provides little if any contribution to system peak needs. Avista therefore assumes wind resources provide no contribution to meeting peak demands. Distributed wind generation should be treated similarly.

7. Does current distribution capacity constrain development of distributed wind generation?

   RESPONSE: No, not at this time. The Company is still able to accommodate wind generators depending on size and location.

Distributed Hydroelectric

8. What is the state of the technology for generating electricity from wave, tidal, and micro-hydro technologies (maturation, market penetration, retail price of installation)?

   RESPONSE: Avista has done some preliminary studies concerning the state of technology for generating electricity from wave, tidal, and micro-hydro technologies as part of the research for the IRP. These technologies have not reached the point of being commercially available for utility use because of their high cost. The prices estimated for tidal and wave generation in our 2009 IRP was $785.63/MWh for 20-year levelized nominal cost ($665.12/MWh in 2009 real dollars). The costs for micro-hydro (hydrokinetics) were estimated to be $147.87/MWh in levelized nominal dollars and $125.35/MWh in real 2009 dollars.

9. Do these technologies pose potential negative environmental impacts?

   RESPONSE: Any negative environmental impacts for these technologies would be highly dependent on the location and the specific technology being used. For example, a micro-hydro project on an irrigation canal with no fish issues should have little if any environmental issues, but a project placed off a bridge or in a stream may have some issues depending on the specific location. Some technologies may also create negative impacts on recreation, aesthetics, fisheries, and habitat depending on the project design and location.

10. Are there potential impacts from current environmental regulations for hydroelectric generation that might adversely affect the development of future distributed hydroelectric generation (in other words, should micro-hydro be treated the same as utility-scale hydroelectric generation? Are there other impacts specific to micro-hydro that ought to be considered)?

    RESPONSE: Some level of permitting or licensing is likely required for any hydro development depending on generation capacity, technology and location. FERC already has modified rules for small hydro, so there may be some level of exemptions for small hydro already in place. There would also be requirements for state water rights and many other permits that may or may not be environmental in nature.

Biogas

11. What is the generation capacity and energy production potential from biogas fuels located in Washington State?

    RESPONSE: Avista has not done any research into the amount of generation potential from biogas fuels located in Washington State. The Northwest Power and Conservation Council (NPCC) through its Sixth Power Plan discuss potential in the Northwest.

Avista's requests for proposals for renewable power in 2006, 2009 and 2011 received few bids from biogas type resources (landfill gas and wood gasification). Avista occasionally receives requests for potential PURPA type resources projects, but we have not recently signed any PURPA contracts for these types of resources.

12. How are fuel mixtures accounted for, and are there fuel mixes with fuel components that do not qualify under the state renewable portfolio standard (RCW 19.285)?

    RESPONSE: Avista does not have any experience with this issue. All of the biogas resources that we have studied through the IRP or RFPs for renewable resources would have received fuel from a single source, such as animal waste or landfill gas.

13. What is the range of project capacity sizes for biogas generation resources and how does that compare to the capacity sizes for projects that qualify for published PURPA rates?

    RESPONSE: The range of project capacity sizes for biogas generation resources is directly related to the size of the gas resource being used for fuel. Most of the capacity sizes are relatively small compared to normal utility scale resources, generally in the 1 to 5 MW range.

14. What is the status of municipal green stream digester development, including the status of the eligibility of those projects or potential projects under RCW 19.285?

    RESPONSE: Avista has not done any research into this topic.

C. Financial Incentives:

1. If the cost of building a distributed energy resource is not yet competitive, and a subsidy is recommended, what form of subsidy is best?

RESPONSE: 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.

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 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

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.

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.

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.

2. What effect would the subsidy have on encouraging the building of the resource versus research and development?

RESPONSE: This question raises an important public policy question, to wit: Should a subsidy be sufficient to encourage development of existing distributed energy technologies, or should it be designed to promote the deployment of innovative technologies that have not been fully commercialized?

The goal of encouraging deployment of a resource is different than an objective of promoting investment in research and development. The latter proposition seems likely to involve the offering of an incentive that would encourage the deployment of commercially unproven technologies – and, more likely than not, it would involve an assumption of costs associated with any risks that may be attendant with them. In other words, the subsidy (of whatever form) may need to be more generous than one designed to stimulate investment in commercially proven technologies, which may only require a subsidy that is adequate to buy-down the above market cost of the resource. The cost of a subsidy to promote technology research and development on utility customers and/or taxpayers may be greater than one designed to promote the use of commercialized technologies.

3. Should subsidies, incentives or renewable energy credits be paid or created for power generated through distributed resources while market prices are negative?

   RESPONSE: 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.

Avista looks forward to participating in the upcoming Work Session on July 25, 2011. If you have any questions regarding these issues, please contact me at 509-495-4975.

Sincerely,

/s/Linda Gervais

Linda Gervais
Manager, Regulatory Policy
Avista Utilities
509-495-4975
linda.gervais@avistacorp.com