Testimony of

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Hearing on Smart Grid Architecture and Standards: Assessing Coordination and Progress

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Good morning Chairman Wu, Ranking Member Smith and other members of the subcommittee. My name is Conrad Eustis – I serve as Director of retail technology development at Portland General Electric. I have 35 years of experience in the energy business and 17 years of experience implementing successful smart grid related projects. In my role at PGE I participate on the utility's behalf in a number of regulatory and technical forums related to smart grid development, including the NIST standards process. Thank you for holding this important hearing on the development of standards for smart grid related technologies.

Portland General Electric is Oregon's largest electric utility. We are a vertically oriented investor-owned utility serving more than 817,000 customers in the Portland area and the Willamette Valley. We're focused on providing reliable electricity supplies at reasonable prices while continuing to be good stewards of Oregon's environment. In part, that means we're leading the charge on clean energy in Oregon.

I am sure it is no surprise to you, Mr. Chairman, that the U.S. Department of Energy has consistently ranked PGE as one of the top utilities for renewable power sales to residential customers. In fact, this year PGE earned DOE's top spot in the nation for having more renewable power customers than any other utility in the nation.

We are also a recognized leader in the development of electric vehicle infrastructure. As a partner in the DOE's historic $100 million ECOtality grant, we expect to see more than 2,000 residential and public charging stations deployed in Oregon by 2013.

Long before the term "smart grid" became commonplace, PGE was investing in smart grid-related innovations – such as our Dispatchable Standby Generation (DSG) program in which we can remotely start and monitor our business customers' standby generation during times of peak demand. In exchange the utility installs telemetry equipment and contributes to its maintenance. We have worked with our regulators to support net metering for solar and other renewables. We've had a residential time-of-use program available since 2001. Today, we are actively deploying smart meters to all 817,000 customers throughout our service territory. We are 90 percent deployed and expect to complete deployment by the end of August. Ultimately, our goal is to be a leader in bringing the benefits of a smarter grid to our customers – providing them with more energy management options while increasing system reliability and efficiency.

Portland General Electric is also pleased to be a partner in the Pacific Northwest Smart Grid Demonstration Project, which will involve more than 60,000 metered customers in Idaho, Montana, Oregon, Washington and Wyoming. Using smart grid technologies, the study will test new combinations of devices, software and advanced analytical tools that enhance the power grid's reliability and performance.

As part of the study, PGE will implement a demonstration project on a distribution feeder in Salem serving residential and business customers. There are three primary objectives for this project: 1) to demonstrate how a batteries together with demand response can be used to create a reliable micro-grid; 2) to determine how the batteries/inverter systems can be operated to provide peak-load following and frequency regulation; and 3) to determine how to position the batteries' storage to accept off-peak wind generation.

At the national level, we greatly appreciate the bipartisan support that passed the Energy Independence and Security Act (EISA) in 2007. That Act sets the course for the current standards making process at NIST and launched some of the most important policy changes for the utility sector in decades. With limited funding, NIST began implementing its responsibilities under EISA in 2008, establishing teams to collect stakeholder input, organizing meetings to create awareness of their effort to gain additional stakeholders and so forth. The passage of the American Recovery and Reinvestment Act provided the funds necessary to really launch this standards process and to create awareness across the 22 stakeholder groups that are required to implement a successful smart grid.

This effort is none too soon for the electric utility sector. Real challenges exist with the transition to lower carbon resources and the large-scale installation of intermittent renewable resources. This will force changes to system operation where smart grid transactions will be the most appropriate solution. However, I think many people have unrealistic expectations of how fast this change will come – even if a full set of standards were available today.

PGE learned that successful implementation of smart grid projects requires careful planning by a small team of cross-functional professionals working nearly full time for two or more years before launching the project implementation team. Successful implementation requires understanding the specific business processes that will need to change and identification of the legacy information systems that must be enhanced to support the new processes. Management must commit subject matter experts and provide training to support new departments while eliminating others. For most utilities, high public expectations for low-cost, reliable power means the vertical organization structure is lean and focused on existing processes. Since our industry has had, historically, levels of research and development expenditures below 0.2 percent of revenues, there are scare funds and scarce resources available to staff the large project teams required to implement a smart grid project. This leads most utilities to seek regulatory support for a new smart grid project from their governance stakeholders. Regulatory buy-in involves more than just the regulators. All, or at least most, stakeholders to the regulatory process must understand the value and benefits that smart grid will bring. This is not any easy task, and requires considerable time for education and due-diligence.

We are active participants in the NIST standards making process. I am PGE’s participating member on NIST’s Smart Grid Interoperability Panel, which had its first meeting in November of 2009. This panel includes 600 plus members from 22 stakeholder groups. To date, we have had only a small role coordinating tasks and gathering input. However, we serve a major role in keeping the more than 600 businesses we represent informed about the many parallel efforts taking place. The coordinating tasks have been managed by NIST directly or through the SGIPGB, and the Priority Action Plan team leaders.

One of the challenges with a standards making process is ensuring that you have industry support and a high level of adoption of the standards that eventually emerge from the process. We feel that NIST has implemented a number of policies to help ensure the utility industry buy-in. These include encouragement for all utilities to participate in the process, the recognition that there are multiple types of utility organizations, a fair governance process, and the beginnings of a public knowledge base to document support for implementing standards. NIST has also put together conferences that disseminate information, issue progress reports, and encourage face-to-face stakeholder input.

Looking ahead, NIST's plans for interoperability testing of standards will also be critical to ensuring industry adoption. Testing is critical with immature standards to determine where additional specifications are required to ensure interoperability. Because of the cost of testing, it also helps prioritize the initial requirements. It is not uncommon to overstate mandatory requirements to reach consensus in the definition stage; testing ensures the most important requirements are interoperable, and that different vendors interpret the written specification in the same way.

The NIST roadmap includes a testing phase to prove interoperability of selected standards from different manufacturers and devices. My understanding is that this phase has not started, or if it has, only recently so. This is the most important part of the NIST plan and will probably be the most expensive and difficult.

There are two additional activities that NIST could implement that we believe would likely improve utility buy-in and adoption.

The first has to do with the fact that the vendors – the suppliers of systems and equipment to utilities – enjoy a "seller's advantage." For a given type of electric utility equipment there are usually about five major international suppliers. It is not uncommon for utilities to keep a relationship with one primary vendor and a second relationship with a back-up vendor. Part of the reason for this approach is because maintenance and operation of each vendor's equipment is somewhat unique to each vendor. While some aspects may be interoperable, the more complex features are often not. This is subtle example of non-inoperability and it allows vendors the opportunity to extract a larger profit margin because of a utility's reluctance to switch vendors. This is a gross simplification to make a point; there have been successes too – particularly in the area of interoperability for substation equipment. But the point remains that the higher margins created by partial interoperability is a potential barrier to higher levels of interoperability. NIST might consider as part of the early testing process, interviewing vendors separately and together to learn the needs of vendors to make standards adoption a higher priority.

Second, a focus on utility IT managers may be valuable. Among utilities, the responsibilities of VPs or general managers of the IT department vary greatly. For many of these managers, most of their time is spent keeping existing systems running smoothly; they have minimal time to focus on evolving and emerging standards. I would not be surprised to find that the average IT manager is minimally informed about the NIST process. NIST might consider engaging a diverse group of these managers, together with purchasing personnel that support them, to help keep them informed and to provide tools for them to require vendors to adopt specific standards. Some of the outcomes might be as easy as the publication of a quarterly update targeted to the utility IT manager.

NIST also needs to focus on developing standards and processes that make sense for consumers and addresses consumer behavior. For example, one complex and low priority transaction involves providing “real time” time usage data from the meter to the home display. While desirable for some customers, most of the value in the usage data is available from non-real time sources like a web page with perhaps a day of delay. PGE implemented a home display pilot in 2003. While half the customers found them interesting, most stopped accessing the displays after about a week. Energy is a low involvement product; effective smart grid implementations in the home will need to emphasize set and forget controls, and not depend entirely on real time involvement for their success. Spending time and money on programs consumers do not want should be avoided.

Now let me return to the issue of interoperability and its importance in the overall smart grid standards process. Fundamentally, the smart grid is about moving data from one system or device to another. This requires not one standard, but at least three to move one byte of data between two separate devices. If security is needed, this adds a fourth standard. In many systems purchased by utilities today, vendors focus on data transactions among devices in their product line. Generally, they design the transactions to minimize their cost to the customer utility – this is especially true of advanced metering infrastructure (AMI) systems. Where a communication device from one vendor is placed in the meter of another vendor, a meter data standard called ANSI C12.19 helps reduce development time. However, because the physical method to pass data and the physical form factor have not yet been standardized, the actual integration of the components still usually takes 6 to 12 months. For new two-way applications between the utility and the home, only immature standards exist. Between major utility enterprise systems – such as an outage management system – the use of a common information model at the application level is unfortunately rare. Small electric cooperatives, municipal utilities and PUDs that use a common application called MultiSpeak® are probably further along than the larger utilities who generally decide that custom applications serve their needs better.

The value in interoperability comes into play when you talk about the future for low-cost mass consumption products. Avoiding $200,000 of custom engineering in a $10 million substation because interoperability is available is still desirable, but the lack of interoperability doesn’t prevent an economic implementation. But chasing after a peak demand savings of 50 watts in a common consumer item like a refrigerator would be impossible unless the total incremental cost is less than $40. This cost can only be met via interoperability.

In thinking about what should be the top priorities for the NIST standards making process going forward, I believe the focus should be to create visible successes that can be implemented with end-to-end demonstrations. Early successes are possible if NIST focuses on very simple transactions; additional or more feature-rich modifications can be added to a standard later. These early successes will build upon themselves and create more utility interest and adherence to the NIST process. My top three suggestions along these lines are:

1) We need a standardized USB-like socket, together with a very simple transaction set, to enable demand response programs with home appliances. If appliance manufactures were to incorporate these sockets on their major appliances over approximately 5 years, including the value-based appliances, utilities would gain the potential of 15,000 MW of demand response every year. Adding the socket without embedded communication hardware minimizes obsolesce and security issues. Since appliances last 10 to 30 years, making them demand response ready is important to prevent a lost opportunity in 5 to 10 years as customer awareness increases. This is the lowest hanging fruit on the smart grid tree, and it would create interest for, and time for, customers to learn about demand response.

Some organizations advocate embedding a specific wireless[1] communication device in the appliance. While the free market should to some extent determine the best approach to creating “smart” appliances, security and interoperability are much more difficult to ensure with embedded communication devices. Consumer adoption of smart gird technologies could be threatened if even one or two bad experiences occur using embedded communication devices.

2) My second suggestion is for standardized smart charging for plug-in-vehicles (PIVs). This is not the same as the vehicle-to-grid concept, which will take more time and requires PIV manufactures to gain more experience with the life of their batteries. This would be the basic standard for allowing PIVs to charge at the most opportune time. While the number of total PIVs in the near term will be small, the visibility of these vehicles as smart-grid friendly will be significant in the popular media. PIVs represent a “green field” development process and represent a great opportunity to gain wide adoption. This would

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[1] Wireless includes radio and power-line communication techniques.

counter the natural resistance that might occur from utilities and vendors to modify their existing systems to adopt a specific standard. Standards are easier to accept when you don’t have to throw away something you already developed.

3) Finally, we need a standardized application for the format and process to send and receive usage data. This format would be used in multiple applications, for example: in meter-to-home applications, among back-office enterprise systems, utility-to-third parties, etc. In a year or two smart meters will be generating multiple petabytes of usage data per year; we need a standard way to move meter usage information around.

Thank you, again, Chairman Wu for your leadership and interest in this issue. I would be pleased to answer any questions the committee may have.