Supporting Documentation

for

Small Modular Reactor Hanford Siting Analysis

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Introduction to Appendices for the Small Modular Reactor Hanford Site Analysis

The enclosed appendices (A through G) provide reference material to the "Small Modular Reactor Hanford Site Analysis" report. Each appendix corresponds with a section in the report. Each appendix is intended to add detailed information from activities and research that were performed during May 2014.

Appendix A, "Current State of New Nuclear Power Generation in the US," provides current SMR technology that is being developed, along with the current state of where the US stands in nuclear power compared to the rest of the world.

Appendix B, "DOE'S Future Power Needs for the Hanford Site and the Northwest Region," was prepared by Independent Strategic Management Solutions, Inc., and provides information and analyses on regional power needs of the Pacific Northwest, namely the Hanford Site, the Pacific Northwest National Laboratory, the City of Richland, and how the Waste Treatment and Immobilization Plant (WTP) affects power usage when it comes online, expected in 2022.

Appendix C, "Future Cost of Power in the Northwest," was also prepared by Independent Strategic Management Solutions, Inc., and provides referenced information on selling power to Bonneville Power Administration or other northwest utilities.

Appendix D is "Base Cost of Construction; Operation of an SMR and WNP-1 Site Utilization and Estimated Cost Savings; Characterization and Licensing Approach and Cost Savings at WNP-1." "Base Cost of Construction" is a presentation given by Energy Northwest in 2013 that discusses the current state of nuclear power plants being constructed in the US, along with cost and advantage to construct and operate an SMR. DOE funding opportunities to construct an SMR are also provided. "Operation of an SMR and WNP-1 Site Utilization Cost Savings" provides results from a site walkdown conducted at the WNP-1 site in May 2013 and cites the cost advantages and avoidances of using WNP-1 with its infrastructure and security and emergency services already in place. "Characterization and Licensing Approach" provides licensing/regulatory requirements and issues and Nuclear Regulatory Commission Regulatory Guidances that are applicable to SMRs. Because of the characterization and site studies that have already been completed at the WNP-1 site, detailed cost advantages are provided in this appendix as to why siting the first SMR at the Hanford Site should be considered.

Appendix E, "Identification and Evaluation of Other Hanford Sites," discusses other locations on the Hanford Site that were investigated to site an SMR. Each location's advantages and disadvantages are provided.

Appendix F, "Funding Strategies," provides the draft preliminary assessment that was prepared by Johnson Controls, Inc. The preliminary assessment focused on constructing a natural gas fired steam plant in the 200 Area of Hanford Site to service the 242-A Evaporator and WTP. It discussed the recommended energy conservation measures that would impact the Hanford Site's overall progress towards DOE energy and sustainability goals.

Appendix G, "Other Potential Cost Savings," discusses economic advantages to siting an SMR in the Tri-Cities community. Resources such as nuclear-trained personnel, local education for such disciplines, and the business environment with which the Tri-Cities performs in to provide a stable community environment are backed up with local and national references.

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Appendix A

Current State of New Nuclear Power Generation in the US

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Introduction

In current terminology, Small Modular Reactors (SMR) may be either light-water or nonlight-water designs, with an electrical generation capacity of 300 megawatts effective power capacity (MWe) or less per module. The 300 MWe classification is consistent with the International Atomic Energy Agency (IAEA) definition used for small and medium sized reactors ("SMR" in IAEA terminology) found in IAEA-TECDOC-999 and other IAEA publications (URL: http://www.amacad.org/publications/nuclearReactors.aspx). For the purposes of NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition," the U.S. Nuclear Regulatory Commission (NRC) considers an SMR to be a light-water power reactor design, with the same electrical generating capacity limitation per module described above.

The U.S. Department of Energy (DOE) defines SMRs as reactors of less than 300 MWe capacity that can be built in a factory and shipped to utility sites in response to consumer demands.

The following SMRs are currently in various stages of development. Each of these SMRs is based on a light water reactor (LWR) design.

- **NuScale Power, LLC Module -**The NuScale Power, LLC (NuScale) Module is a new kind of nuclear power plant – a smaller, scalable version of pressurized water reactor technology with natural safety features which enable it to safely shut down and self-cool, with no operator action, no AC or DC power, and no external water. Each NuScale Power Module has a power capacity of 45 MWe and has a fully integrated, factory-built containment and reactor pressure vessel. The NuScale SMR will be mass-produced in a factory and shipped by truck, rail, or barge in sets of up to twelve modules for power stations having generating capacities between 45MWe and 540MWe.
- **Babcock & Wilcox Co. (B&W) Generation mPower™ Reactor -** The B&W mPower reactor design is a 180-megawatt electric advanced light water reactor design that uses natural phenomena such as gravity, convection and conduction to cool the reactor in an emergency with a below-ground containment.
- **Holtec International (Holtec) SMR-160 -** The Holtec SMR-160 is a 160-megawatt reactor with an underground core. Holtec contends that there is, therefore, no need for a reactor coolant pump or off-site power to cool the reactor core.
- **Westinghouse SMR -** The Westinghouse SMR is a 200-megawatt integral pressurized water reactor with all primary components located inside the reactor vessel. It is based on the established Westinghouse AP1000 reactor design, which is being built in many new nuclear plants around the world.

Status and Funding Support for Developing SMRs

In 2010, the U.S. Department of Energy (DOE), Office of Nuclear Energy, requested Argonne National Laboratory (ANL) to update *The Economic Future of Nuclear Power* (August 2004). In addition to the follow-on examination of large light water reactor plants, DOE also requested that ANL begin to examine the economics of SMRs.

Until recently, planning and design work on SMR technologies was at a relatively early stage. NuScale, along with Babcock & Wilcox (B&W), Holtec International, and Westinghouse, applied for DOE's SMR development program in 2012. The DOE selected B&W's mPower

SMR design in that first solicitation. Under cooperative agreements with DOE, B&W will receive $150 million-$226 million of the $452 million available through the program. B&W spent about $80 million on its mPower SMR design in 2013. B&W has received approximately $101 million to date.

The DOE announced a second solicitation in March 2013 for proposals with the potential to deploy an SMR around 2025. In December 2013, the DOE announced that it would fund up to half the cost of developing, licensing and commercializing NuScale’s 45 MWe reactor - the NuScale Power Module. In a subsequent letter to the US Nuclear Regulatory Commission (NRC), Westinghouse indicated that, as a result of the DoE's decision, it was "re-assessing its design certification application schedule."

The DOE and NuScale signed a formal agreement on May 27, 2014 in which NuScale will receive up to $217 million over five years for SMR development (Platts Nucleonics Week 2014). NuScale joins Babcock & Wilcox (for its 180 MWe mPower SMR) in receiving money as part of a six-year program DOE initiated in 2012 to distribute $452 million to support licensing and development of SMRs. These DOE funds will be used for design engineering, testing and work needed to receive design certification from the US Nuclear Regulatory Commission (NRC).

The B&W and NuScale SMR awards provide additional financial incentives for the NuScale SMR and B&W mPower SMRs to advance to the implementation stage, compared to other SMRs that have recently been under consideration (e.g., Westinghouse SMR and Holtec International SMR).

NuScale intends to use the funds to test their reactor and to complete the process of certification through the U.S. Nuclear Regulatory Commission (NRC) with hopes of having the first NuScale SMR online by 2023. However, B&W indicated said in April 2014 that it would spend no more than $15 million a year on its SMR project, starting in the third quarter, because the company was unable to secure investors and customer contracts.

Holtec announced in July 2014 that is preparing to build a $260 million factory, reactor test loop and engineering building for testing to help advance its SMR-160 reactor and fuel storage technology. The factory is expected to be completed in 2017 and commissioned in mid-2018 (NuclearEnergyInsider 2014). After Holtec's bid lost the second round of US DOE funding for SMR development, the company vowed that it would continue developing the reactor on its own.

SMRs Currently in Various Stages of Development

NuScale SMR

The NuScale SMR is a 150 MWt (45 MWe) natural circulation LWR design that consists of a self-contained assembly with the reactor core and steam generators located in a common reactor vessel. The reactor uses approximately one-half-height LWR fuel rods (less than 5-percent enrichment) arrayed in 17 ft x17 ft bundles. The NuScale light-water reactor design employs a non-traditional, small containment for each module that operates in a common, large pool of water. Electrical power conversion involves the use of steam generators and a steam turbine-generator. According to the NRC (NRC 2010), NuScale plans to submit a design certification application for a 12-module facility. These modular units would be manufactured at a single centralized facility; transported by rail, road, and/or ship; and installed as a series of self-contained units, each with a 24-month refueling cycle.

A graphic depicting a portion of the containment system for the proposed NuScale SMR is included in **Figure 1**.

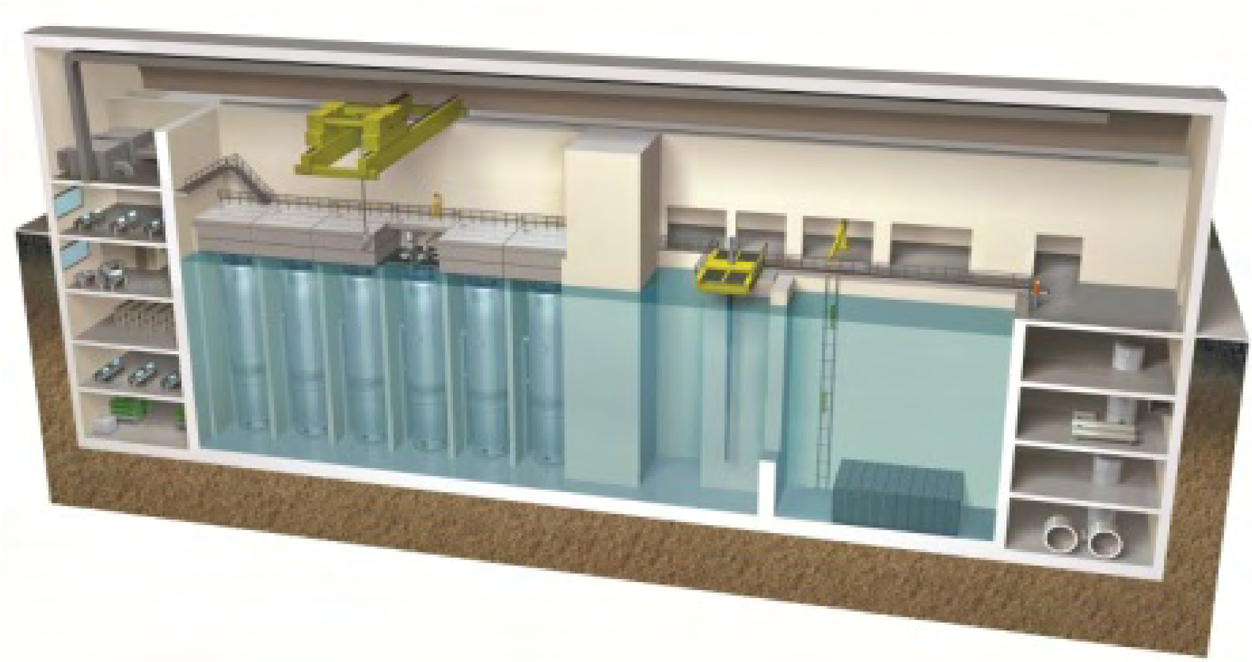

Figure 1. NuScale SMR Containment Vessels Design: *NuScale reactors are housed inside steel containment vessels and submerged in a large pool of water below ground level in the reactor building (Image Source: http://www.world-nuclear-news.org/NN-Federal-funding-agreed-for-NuScale-2905144.html).*

Babcock & Wilcox Co. Generation mPower SMR™

The B&W Generation mPower™ reactor design is a scalable, modular, Advanced Light Water Reactor (ALWR) system in which the nuclear core and steam generators are contained within a single vessel. The electric generation plant has the capacity to furnish customer needs in nominal 180 MWe increments for a four-year operating cycle without refueling, using standard pressurized water reactor (PWR) fuel.

B&W has established an Integrated System Test facility in Bedford County, Virginia. The facility is designed to collect data to verify the reactor design and safety performance in support of licensing activities with the Nuclear Regulatory Commission. The facility contains a scaled prototype of the B&W mPower reactor. A graphic depicting a portion of the mPower SMR ™ is included in **Figure 2**.

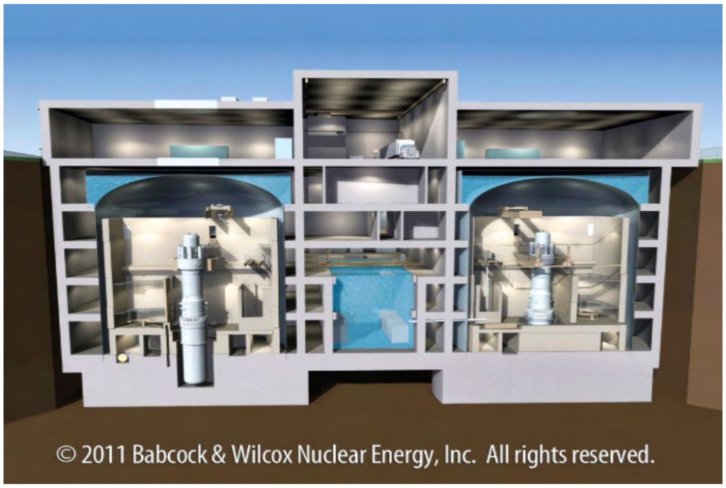

Figure 2. B&W mPower SMR Cutaway *(Image Source: http://www.generationmpower.com/technology/deployment.asp).*

Holtec SMR

Pre-application interactions between B&W and the NRC for this SMR began in July 2009. Generation mPower continues to work with the U.S. Nuclear Regulatory Commission (NRC) in licensing activities to support deployment of the first B&W mPower reactor. The company has submitted a number of topical and technical reports to the NRC, and more are scheduled. B&W notified the U.S. DOE in April of 2014 of it plans for reduced spending, indicating it would work with the DOE and other stakeholders during the next one to months to confirm the best path forward to develop a mutually agreeable plan including milestones for continuing the cost-shared industry partnership program. B&W indicated that it expects to invest up to $15 Million annually, beginning in the third quarter of 2014.

Major features of the Holtec SMR-160 are its small footprint (5 acres), small site boundary dose, large inventory of coolant in the reactor vessel and its modularity - allowing project owners to build the number of units to meet current and future demand. The small physical plant size and the reduced scope of equipment and systems are intended to reduce capital investment requirements as well as security and maintenance costs. Holtec indicates that after the licensing process is completed for this SMR and the first unit is built (to help streamline the construction process), the time from “the first shovel in the ground to the completion of erection” is expected to be less than 18 months. A graphic depicting a portion of the proposed Holtec SMR-160 SMR is included in **Figure 3**.

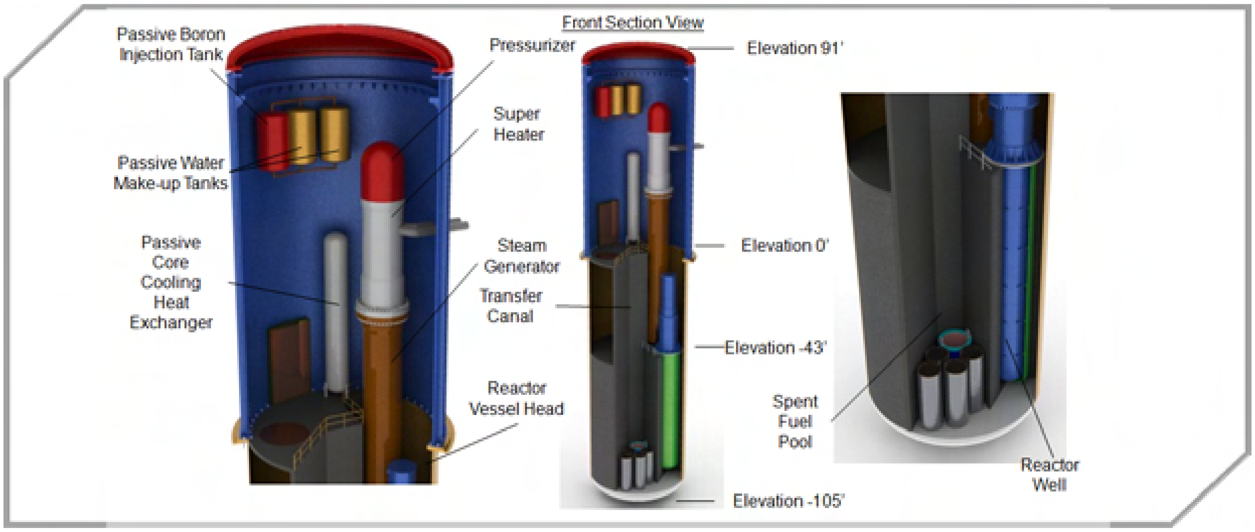

***Figure 3. Holtec SMR-160 SMR Cutaway:** The SMR-160 uses gravitational force for running the reactor and safety functions, rather than large reactor coolant pumps (Image Source: http://www.smrllc.com/economical.html).*

SMRs Currently Under Consideration for Installation at Hanford Site

The type of SMR currently being considered for installation at the Hanford Site (e.g., either at the "WNP-1" or "WNP-4" site) is an SMR having an effective power capacity of up to approximately 270 MWe. If the NuScale SMR were to be selected for installation, for example, this would require a multi-module SMR consisting of six (6) 45 MWe Power Modules.

The layout of an SMR facility at either the WNP-1 or WNP-4 site would depend on the specific SMR technology and manufacturer selected. An example (conceptual) SMR plant layout (for a B&W mPower SMR) is provided in **Figure 4**.

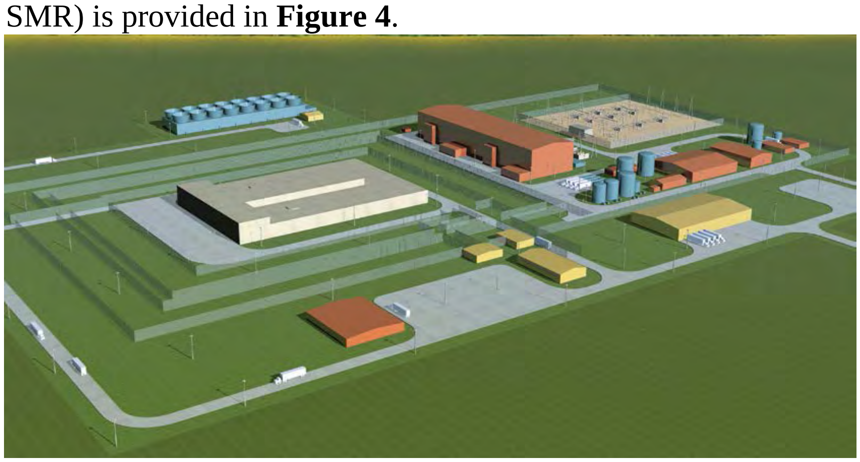

***Figure 4. Example SMR facility Conceptual Layout (for the case of a B&W mPower SMR Plant):** Generation mPower "Twin Pack" facility layout with Water-Cooled Condenser (Image Source: http://www.generationmpower.com/pdf/sp201100.pdf).*

Current State of Nuclear Power Production and Growth

As of 2014, 100 nuclear power reactors operate in the United Sates, generating approximately 590 terawatt hours of electricity.[1] This amount represents about 19 percent of the electrical generation in the United States, and about 69 percent of the nation's carbon-free power. The United States currently generates approximately one-third of the electricity coming from nuclear

[1] A terawatt is equal to one trillion watts.

power in the world, and operates more reactors than any other nation.[2] However, the U.S. share of nuclear power production is rapidly falling behind, as much of the rest of the world rapidly expands nuclear power.

Worldwide, 72 reactors are currently under construction, but only five of those are in the U.S. Worldwide, 174 reactors are actively in the planning stages, with only five in the U.S.[3] China has announced its intention to increase nuclear energy production for peaceful (industrial and consumer) purposes by *20-fold* by the year 2030. [4] India is building to produce half of its energy from nuclear power by 2050. Since it now produces only about one percent from nuclear energy, this statistic means that India's nuclear output will increase by *50-fold* in the next 36 years.[5] Russia is actively building now to increase its peaceful nuclear energy production by 50 percent by 2020—just six years from now. Another doubling of Russia's nuclear energy production—beyond the 2020 figures—is expected by 2030.[6] These nations are building nuclear plants rapidly with the intention that nuclear energy will become their main base load power source. In fact, nuclear power reactors are being built on every continent in the world except Australia, even in several nations in the oil-rich Middle East.

Causes of Stagnation of U.S. Nuclear Power

U.S. nuclear plants are aging and the U.S. share of nuclear power production is quickly falling behind, as much of the rest of the world rapidly expands nuclear power. The two oldest nuclear plants in the U.S. are 45 years old, and the rest average 33 years old.7 Most U.S. nuclear plants originally were licensed for a 40-year period, and 73 of them have received 20-year license extensions. Fourteen more have filed for license extensions, and 15 more are expected to file through 2018.8 Reactor orders and construction were very rapid in the U.S. during the 1960s and first four years of the 1970s. However, extremely high inflation rates caused by the oil

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2 World Nuclear Association (WNA), "Nuclear Power in the World Today," WNA (London, United Kingdom), April 2014 at http://www.world-nuclear.org/info/Current-and-Future-Generation/Nuclear-Power-in-the-World-Today/

3 Ibid.

4 WNA, "World Nuclear Power Reactors and Uranium Requirements," WNA (London), October 2012 at http://www.world-nuclear.org/info/reactors.html; Nuclear Energy Institute (NEI), "World Nuclear Power Plants in Operation," NEI, (Washington, DC), August 2012 at http://www.nei.org/resourcesandstas/documentslibrary; Stanway, David, "Special Report: In China the Big Nuclear Question is 'How Soon'?" in *Reuters*, May 3, 2011 at http://www.reuters.com/article/2011/or/o3/us-china-nuclear-idUSTRE7240V420110503; Kidd, Steve, "Nuclear in East Asia—the Hotbed?" *NEI Magazine*, December 2011 at http://www.neimagazine.com/story.asp?stpryCode=2061333

5 WNA, "World Nuclear Power Reactors and Uranium Requirements;" *American Free Press* (AFP), "India Foresees Sharp Rise in Nuclear Power," *AFP* (Washington, DC), August 20, 2009 at http://www.google.com/hostednews/afp/article/ALeqM5jDcQmyGqCr4CbK0zHDYJillfg

6 WNA, "World Nuclear Power Reactors and Uranium Requirements;" Weir, Fred, "Russia Plans Big Nuclear Expansion," in *Christian Science Monitor*, July 7, 2007 at http://www.csmonitor.com/2007/0717/p01s04-woeu.htm; WNA, "Nuclear Power in Russia," WNA, September 2012 at http://world-nuclear-org/info/inf45.html

7 U.S. Energy Information Administration (EIA), "Frequently Asked Questions," EIA (Washington, DC), May 16, 2012 at http://www.eia.gov/tools/faqs/faq.cfm?id=228&t=21; Johnson, Jeff, "Nuclear Retirement Anxiety," in *Chemical & Engineering News* (American Chemical Society: Washington, DC), Vol.91, Issue 13, pp. 14-17.

8 NEI, "License Renewal," NEI, 2013 at http://www.nei.org/resourcesandstats/nuclear_statistics/License-Renewal;

embargo levied against the United States in 1973 resulted in high financing and construction costs, and caused orders to fall off sharply. The nation's inflation rate averaged only four percent per year in the nine years of peak reactor orders, 1965 through 1973. However, the rate shot up to 11 percent in 1974, and averaged eight percent during the five years 1973-1978 – exactly double the rate during the years of peak reactor orders.9 Only a few reactors were ordered during 1974-77, none were ordered in 1978, and in fact delays and cancellations began to occur. Poor project performance and cost overruns at plants being constructed in the 1970s, and tighter and lengthier regulations after the Nuclear Regulatory Commission (NRC) was created in 1974, further contributed to the unwillingness of utilities to build more nuclear plants.

In March 1979, the nuclear industry received perhaps its most serious setback when an accident occurred at the Three Mile Island Unit 2 plant in Pennsylvania. Although the accident was minor, fear and distrust of nuclear power became major. Fears about the accident were magnified by the fact that a movie titled *The China Syndrome*, dramatizing a reactor meltdown and release of radiation in California, was released in theatres just 12 days before the Three Mile Island accident. The official Department of Energy (DOE) history of the Three Mile Island event states that "Three Mile island, then, should be understood as an event of historical significance not only because of what actually happened, but because of what people thought was happening or feared might happen...the line between real and imagined risk became blurred: citizens were no less traumatized because the event happened to them emotionally. Risk perceived is risk endured."[10]

After 1978, all existing orders for power reactors in the U.S. were cancelled, and the industry remained flat in the U.S. until Georgia Power Co. ordered two reactors known as Vogtle Units 3 and 4 from Westinghouse-Toshiba in 2008.[11] That same year, South Carolina Electric and Gas ordered two more reactors named V.C. Summer Units 2 and 3. In 2007, the Tennessee Valley Authority re-activated construction of Watts Bar Unit 2, which had been suspended many years earlier.

Current Factors Affecting Nuclear Plant Construction in U.S.

Although a "nuclear renaissance" was predicted and perhaps emerging during the earliest years of the 21st century, no such surge has occurred in the United States. A main reason is that vast deposits of natural gas have been discovered just recently, along with new technologies to extract the material. The Marcellus Formation, a huge unit of marine sedimentary rock extending underneath about 95,000 square miles of the eastern United States and into southern Ontario, contains enormous quantities largely untapped natural gas reserves. Estimates of these quantities differ so widely that it is difficult to place faith in them at this time, but it suffices to say there are many trillions of cubic feet. In 2013, about 3.2-trillion cubic feet were extracted from the Marcellus Formation, and its proximity to the high-demand markets along the East Coast of the

[9] U.S. Inflation Calculator, "Historical Inflation Rates, 1914-2014," COIN News Media Group (San Antonio, TX), June 2014 at http://www.usinflationcalculator.com/inflation/historical-inflation-rates/
[10] Cantelon, Philip, and Williams, Robert, "Crisis Contained: The Department of Energy and Three Mile Island," Southern Illinois University Press (Carbondale), 1982, pp. xvii and ix.
[11] Southern Company, "Construction Timeline," Southern Company (Atlanta, GA), 2014 at http://www.southerncompany.com/what-doing/energy-innovation/nuclear-energy/photos.cshtml

United States makes it an attractive target for energy development.[12] In addition, the Bakken Formation, lying beneath the Williston Basin in North Dakota and parts of Montana, Saskatchewan and Manitoba in Canada, sprawls approximately 200,000 square miles. The U.S. Geological Service has estimated that the Bakken Formation in the United States alone could contain about two trillion cubic feet of gas and another 150-million barrels of natural gas liquids.[13] These supplies are in addition to the Barnett Formation beneath north central Texas, the Eagle Ford shale deposits beneath the Permian Basin in west Texas, and other formations along the Texas-Louisiana Gulf Coast, which had been thought to hold 23 percent of America's natural gas, until recently. These formations are huge, allowing Texas to produce up to seven trillion cubic feet per year.

Natural gas plants are currently seen by utilities as less risky and more attractive than nuclear plants, because they relatively easy and quick to construct, so their capital costs are low. By contrast, nuclear plants are capital-intensive and relatively slow to construct. The U.S. Energy Information Administration (EIA – a part of the DOE) places the cost of constructing a conventional Natural Gas Combined Cycle (NGCC) plant at just 16.5 percent of that of constructing a nuclear plant. For an advanced NGCC plant, the cost is just 18.5 percent that of a nuclear plant, and even for an advanced NGCC with a carbon capture system, the construction cost is just 37.8 percent that of a nuclear plant. Further, these costs have declined 10 percent in just the past year.[14] The two Vogtle Units 3 and 4 now under construction are estimated to cost about $7-billion each, while an NGCC may cost $1-billion to $2.5-billion depending on size and the presence of absence of a carbon capture system. An NGCC can be built in two years in most cases, while the nuclear plants currently under construction in the U.S. are projected to take seven-eight years to construct after the license to construct has been granted by the NRC. The total time from reactor order to operating plant is approximated at 10 years. Many if not most corporate Boards of Directors and Chief Operating Officers prefer to manage the risks of construction and financing for as short a time period as possible, naturally giving them a preference for short-term NGCCs as opposed to nuclear plants.

Factors Affecting the Future of Nuclear Plant Construction in the U.S. Costs

Once nuclear plants are constructed, their fuel costs are relatively low, partly because these costs are stable. At present, the EIA estimates that fuel costs for a nuclear plant total only 24-25 percent those of an NGCC, and only 21 percent those of an NGCC equipped with a carbon capture system.[15]

Future prices for NGCC fuel are likely to go higher, as many states and even the Congress debate carbon taxes or fees, environmental controls on the new extraction techniques of fracking and horizontal drilling, and tighter regulation of pipelines. Fracking injects large amounts of

[12] Begos, Kevin, "Marcellus Shale Natural Gas Output Rising Fast," *Christian Science Monitor (*Boston), August 15, 2013 at: www.csmonitor.com/Environment/Latest-News-Wires/2013/0815/Marcellus-Shale-natural-gas-output-rising-fast

[13] "Bakken Shale," Unconventional Oil and Gas Report (PennWell Corp: Houston), 2013 at: www.ogj.com/unconventional-resources/bakken-shale.html

[14] U.S. EIA, "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants," EIA (Washington, DC), April 12, 2013 at http://www.eia.gov/forecasts/capitalcost/

[15] U.S. EIA, "Cost and Quality of Fuels for Electric Plants Report," EIA (Washington, DC), August 2014 at http://www.eia.gov/electricity/data/eia923/

hazardous chemicals deep into the ground, along with the sand, to fracture the rock formations. These chemicals include many acids, carcinogens, mutagens, hazardous air and water pollutants and even unknown substances. In 2010, the Committee on Energy and Commerce of the U.S. House of Representatives asked 14 oil and gas service companies to disclose the chemicals they used in fracking between 2005-2009. The companies revealed that they used 2,500 hydraulic fracturing products containing 750 chemicals and other components, in a volume of 780 million gallons liquids not including water added. In some cases, the companies were unable to provide the Committee with a complete chemical makeup of the hydraulic fracturing fluids they used because the chemicals were proprietary to their chemical suppliers. In the period of interest, the companies used 94 million gallons of 279 products that were unknown to the user. Because some of these chemicals can and have escaped into groundwater, and/or the air, at least 19 state legislatures have introduced or passed more than 100 bills to restrict fracking , and the Environmental Protection Agency (EPA), which regulates the chemical components, now may be readying plans to regulate the entire process of fracking.[16]

Even if gas is successfully retrieved from the deep underground environment, it still must be transported to end users. Transport can happen in pipelines (the cheaper alternative), or by first liquefying the gas and transporting it by truck, train or ship to end users. Pipelines have their own issues, including permits, environmental impact studies, pressurization, accidents, capacity, flooding, escaping radon gas and the effects on communities of “boom and bust cycles.” These concerns can only grow exponentially as natural gas companies race to transport and sell more gas. Legislatures and government agencies can be expected to respond with tighter regulations, which, along with extraction regulations and the perennial threat of a carbon tax or fee, can only increase the costs of natural gas over time.

Supply

Another factor that may diminish the appeal of natural gas is that it will not last through the 21st century. The EIA estimates that there are about 2,214 trillion cubic feet of natural gas that is technically recoverable in the United States. Using the rate of U.S. natural gas consumption in 2013 of about 26 trillion cubic feet per year, the recoverable supply is enough to last about 85 years.[17] If demand rises due to attractive pricing, the supply will last even less time, and if natural gas plants replace coal plants in substantial numbers, projected supplies will last less than 65 years and gas prices will rise and become less attractive relative to other energy sources such as nuclear. Either way, such a supply cannot fuel our nation even throughout this century.

[16] Committee Staff, “Chemicals Used in Hydraulic Fracturing,” Committee on Energy and Commerce, U.S. House of Representatives (Washington, DC), April 2011 at www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=15&ved=0CI8BEBYwDg&url=http%3A%2F%2Fdemocrats.energycommerce.house.gov%2Fsites%2Fdefault%2Ffiles%2Fdocuments%2FHydraulic-Fracturing-Chemicals-2011-4-18.pdf&ei=b7JlUt3ENereigKKkoCQBg&usg=AFQjCNEmn--_QbVgXixyfVGL8SXDxGCz-w&bvm=bv.55123115,d.cGE; Pless, Jacqueline, FRACKING UPDATE: WHAT STATES ARE DOING TO ENSURE SAFE NATURAL GAS EXTRACTION National Conference of State Legislatures (NCSL), (Washington, DC), July 2011 at http://www.ncsl.org/research/energy/fracking-update-what-states-are-doing.aspx

[17] U.S. EIA, “U.S. Natural Gas Total Consumption,” EIA (Washington, DC), 2013 at http://www.eia.gov/dnav/ng/hist/n9140us2a.htm

Political Factors

Carbon taxes or fees have been listed as a possible reason that natural gas prices may rise. Natural gas is a carbon-based, not a clean, carbon-free energy source. While its carbon dioxide (CO2) emissions are below those of coal and oil, natural gas emissions are still significant. They are about 30 percent less than those from oil, and according to the EPA, about half those from burning coal as fuel. Nitrous oxides are also released by burning natural gas, and methane gas, which captures the heat from the Earth, is released during fracking. In light of the 2013 report by the Intergovernmental Panel on Climate Change[18], released in 2014, warning of dire consequences from the continued burning of fossil fuels, lawmakers at all levels are likely to demand tighter regulations on all fossil fuels. The trend is certainly in that direction.

Recognizing this trend, the DOE is sponsoring development of a Next Generation Nuclear Plant (NGNP), a high-temperature gas-cooled reactor, as part of its Generation IV program. DOE is pursuing fuels and materials development, research and development and a licensing strategy. Areva holds a contract with DOE for NGNP development.[19] In 2012, DOE and the Savannah River Site (SRS) announced three public-private partnerships (Memoranda of Agreement) to develop deployment plans for small modular nuclear reactor (SMR) technologies at SRS facilities. DOE stated that these partnerships underscored its commitment to advancing the next generation of nuclear reactor technologies and breaking down the technical and economic barriers to deployment of SMRs. The DOE, SRS and Savannah River National Laboratory (SRNL) entered into agreements with Hyperion Power Generation Inc.; SMR, LLC, a subsidiary of Holtec International; and NuScale Power, LLC. The agreements are aimed at helping these companies obtain information on potential SMR reactor siting at Savannah River and provide a framework for developing land use and site services agreements to further these efforts.[20]

Summary

The Unites States is falling behind much of the rest of the developed and developing world in developing nuclear power, a clean and stable baseload energy source. Until the mid-1970s, the U.S. led the world in building nuclear power plants, but costs and fears stopped development for many years. Recently, the U.S. has begun to build a few reactors, but is not replacing the number of reactors being shut down. Natural gas, an energy competitor, is seen by many as a promising and abundant energy source that is cheaper than nuclear energy. However, natural gas has issues and uncertainties that will almost surely drive up the price, its supply is not unlimited, and it is a fossil fuel in a time when fossil fuels are becoming more unpopular and will likely see more regulation and taxation. Recognizing these facts, DOE has programs to support nuclear development, including SMRs. The time and circumstances are right for a Hanford-based SMR.

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Electricity Generating Portfolios with Small Modular Reactors

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ABSTRACT

This paper provides a method for estimating the probability distributions of the levelized costs of electricity. These probability distributions can be used to find cost-risk minimizing portfolios of electricity generating assets including Combined-Cycle Gas Turbines (burning natural gas), coal-fired power plants with sulfur scrubbers, and Small Modular Reactors, SMRs. Probability densities are proposed for a dozen electricity generation cost drivers, including fuel prices and externalities costs. Given the long time horizons involved in the planning, construction, operation, refurbishment, and post-retirement management of generating assets, price data from the last half century are used to represent long-run price probabilities. This paper shows that SMRs can competitively replace coal units in a portfolio of coal and natural gas generating stations to reduce the levelized cost risk associated with the volatility of natural gas prices and unknown carbon costs.

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Section 1: The Levelized Cost of Electricity

In the U.S. from the 1930s through the 1980s, electricity generating plants were built under either (1) some form of government or cooperative ownership, or (2) some form of private ownership with monopoly distribution rights and rate-of-return regulation. To satisfy growing demand, in a rate-of-return regulated utility or state-owned enterprise making the decision regarding what electricity generating technologies came down to the question: “What’s the cheapest?” During the last half century, a single economic metric has been employed to determine the projected costs of generating electricity: the levelized cost of electricity, LCOE. See definition of levelized cost in NEA-IEA (2010). The levelized cost methodology assigns all costs and revenues to years of construction, operation, and dismantling. Each cost in each year is discounted to the start of commercial operation at an appropriately weighted average cost of capital, such as 7.5%. The “levelized cost” is the tariff that equates the present values of investments, expenditures, and revenues, including a rate-of-return on both debt and equity.

However, *ex ante* when the levelized cost of a new technology is calculated, there are unknowns and uncertain variables in the calculation such as construction cost and duration, operating expenses, and fuel costs. Most calculations of levelized cost of electricity assume that each of the variables is represented by a single, best estimate, or a range of reasonable estimates. Unfortunately, given the uncertainty of future projections, a single best estimate for these variables is not likely to be as reliable as knowing a probability distribution for each of the cost drivers. This will allow the LCOE to be shown as a distribution that reflects these uncertainties.

Given the lengthy life times of electricity generators, constructing generating assets requires a long-term time horizon, something that is not necessarily built into unregulated electricity markets. As electricity markets deregulated, U.S. electric utilities moved toward natural gas, because during much of the day, natural gas prices set the marginal cost of electricity, hence its price in deregulated markets. If the producer is burning gas, it will at least do as well as the rest of the sellers of electricity from natural gas. But this “dash to gas” also led to volatile electricity prices, following price volatility in the natural gas market. The cost structure of generating electricity from natural gas leaves it particularly susceptible to this volatility because it is the technology with the highest share of its LCOE coming from fuel costs. Consumers must either accept this price risk or look to long-term bulk sales to reduce it.

Therefore, given the complexity of complete electricity markets and the lack of a long-term prospective in many of the remaining markets, there is a role for public policy in helping to encourage the building of portfolios of generating assets to (1) minimize total cost and cost risk, (2) minimize carbon dioxide emissions, and (3) maximize energy security for the nation through the diversification of electricity generation. This paper describes how to approximate the probability distributions of levelized cost drivers, how to simulate the levelized cost of electricity, and how to use these probability distributions to construct generating asset portfolios to minimize the cost risk associated with volatile energy prices, volatile weather conditions, volatile international energy markets, and volatile international relations.

The analysis relies on modern portfolio theory to provide a framework to investigate the risk-return tradeoffs of a portfolio of electricity generating technologies. Portfolio theory was developed in the 1950s to evaluate different combinations of financial assets (stocks, corporate bonds, government bonds, etc.) to assess how the resulting portfolio would be expected to perform both in terms of likely returns, and the risks that the holder would have to bear. Portfolio theory has been the basis of financial planning for the last half-century, especially driving home the importance of having diversified portfolios to minimize risk while preserving returns. At the heart of this finding is that having assets that do not move together reduces volatility of the portfolio while preserving its expected long-term value (such as a portfolio of stocks with volatile returns and bonds with more stable returns). This paper applies the models that were developed to assess these financial tradeoffs to electricity generating portfolios. (For an application of real options theory to the choice of new nuclear in Texas, see Rothwell 2006.)

Because of the near lack of cost correlation between nuclear power and fossil-fired plants, nuclear power can balance the levelized cost of portfolios of fossil-fired power plants. Small Modular Reactors, SMRs, show promise in replacing coal units while natural gas prices are low and could be built to replace natural gas units as the price of natural gas rises.

This paper simulates the levelized costs of SMRs, Combined-Cycle Gas Turbines, CCGTs, burning natural gas, and coal-fired power plants with sulfur scrubbers, COAL (compare with Lévêque, 2013, pp. 48-60). Because the technology for producing energy is fixed during the life of the plant, total construction cost, *KC*, and hence, levelized capital cost, are fixed at the time of construction completion; capital additions are expensed in the levelized cost model and added to Operations and Maintenance costs, *O&M*. (Refurbishment costs are not included in this analysis.) Unless otherwise specified, all monetary values are in 2013 dollars. In this context, the levelized cost per megawatt-hour, MWh, can be defined as

$$LC_k = [[\mathrm{FCR}(\mathbf{r}) \cdot KC(OC_k, \mathbf{r}, lt_k)] + FUEL_k\,(F_k, p_{Fk}) + O\&M_k\,(L_k, \mathrm{p_L})] \,/\, E_k\,, \qquad (1.1.1)$$

where

- k indicates the power generating technology, S for SMR, G for CCGT, or C for coal, etc.;
- FCR is the Fixed Charge Rate (also known as the Capital Recovery Factor, CFR) is a function of the cost of capital, **r**, and the plant's depreciation life, T:

  $$\mathrm{FCR} = [\mathbf{r}\,(1+\mathbf{r})^{\mathrm{T}} / [(1+\mathbf{r})^{\mathrm{T}} - 1]\,; \qquad (1.1.2)$$

- $KC(OC_k, \mathbf{r}, lt_k)$ is the total construction cost, which is a function of the overnight cost, OC_k (which is a function of the size of the plant, MW_k), the cost of capital, **r**, and the lead time of construction, lt_k; the product of FCR and *KC* yield a uniform *annual* payment to investors;
- $FUEL_k\,(F_k, p_{Fk})$ is the *annual* fuel payment and a function of the amount of fuel, F_k, and price of fuel, p_{Fk};
- $O\&M_k\,(L_k, \mathrm{p_L})$ is the *annual* Operations and Maintenance expense and a function of the amount of labor, L_k, and the price of labor, $\mathrm{p_L}$ (which is assumed uniform across the generating industry); and
- E_k is annual energy output:

$$E_k \quad = \quad \mathrm{MW}_k \cdot \mathrm{TT} \cdot CF_k, \tag{1.1.3}$$

where MW_k is the size of the power plant in megawatts, TT is the total time in hours in a year, and CF_k is the power plant's annual capacity factor. Capacity factors are discussed in Section 2.7 for nuclear power plants and in Section 3 for fossil-fired power plants. (Other operating modes, intermittent renewables, such as wind, will be added in future work.)

In Equation (1.1.1) some elements are considered parameters (and are represented in non-Italic fonts) and assigned specific values; the influence of these values is determined with sensitivity analysis. The parameters include (1) the cost of capital, **r**; (2) the life time of the plant, T; (3) the price of labor, p_F ; (4) the size of the plant, MW; and (5) the total number of hours in a year, TT. The remaining elements are variables that can be functions of other parameters and other variables, such as in Equation (1.1.3), where the random variable E_k is a function of the parameters MW and TT and the random variable CF_k. Using historic data, random variables are modeled with reasonable probability distributions. The probability distributions for the LC_k in Equation (1.1.1) will be determined using a Monte Carlo process and compared with other generation technologies and in portfolios of electricity generators.

Section 2 discusses the parameters, variables, and levelized cost of Small Modular (Light Water) Reactors, SMRs, based on the costs of Advanced Light Water Reactors, ALWRs. Section 3 discusses the parameters, variables, and levelized cost of natural gas and coal-fired power plants. Section 4 calculates the expected levelized costs and standard deviations of portfolios of generating assets. Section 5 summarizes the conclusions.

Section 2: The Levelized Cost of Electricity of New Nuclear Power

This section provides a method for estimating the probability distributions of levelized costs of new nuclear power, in particular, SMRs. Although ALWRs will not be included in the portfolio analysis, SMR costs are derived from the costs of ALWRs, given that many of the SMRs under development are Light Water Reactor technologies. Section 2.1 discusses the appropriate cost of capital under different regulatory programs in the U.S., and how to calculate the accumulation of financing costs during construction. Section 2.2 discusses appropriate contingencies on cost estimates and argues that the cost engineering literature on contingency is compatible with setting the contingency based on the standard deviation of the cost estimate. (The Appendix extends this discussion and introduces the literature on portfolios of financial assets.) Section 2.3 estimates new nuclear's total construction cost and shows that the estimated overnight cost of a new ALWR unit in the U.S. can be modeled with a probability distribution with a mode of \$4,400/kW and a standard deviation of \$460/kW. Section 2.4 introduces a "top-down" model of SMR levelized cost. Section 2.5 through Section 2.7, respectively, discuss new nuclear's power fuel costs, Operations and Maintenance (O&M) costs, and new nuclear's capacity factor. Section 2.8 presents estimates of the probability distribution of new nuclear's levelized cost of electricity.

Section 2.1: The Cost of Capital and Interest During Construction

Various public policy instruments have been proposed to lower the cost of capital to investors in new nuclear. To determine the impact of these instruments on the cost of capital, this section discusses the results of a cash flow model to calibrate changes in the WACC, "Weighted Average Cost of Capital," **r**, with US Government taxes and policy instruments. (Rothwell, 2011, pp. 88-91, provides a detailed discussion of the cash flow model that was used in MIT, 2003, University of Chicago, 2004, and MIT, 2009.) Based on this literature, in this paper, levelized cost will be calculated for *real* weighted average costs of capital, WACC, of

- 3%, appropriate for self-regulated, state-financed utilities (e.g., TVA, see OMB 1992 on financing government projects); this can be considered the baseline "risk-free" rate (because tariffs or taxes can be raised to pay investment costs);
- 5%, appropriate for state-regulated utilities with Construction Work in Progress, CWIP, financing with access to loan guarantees and production tax credits;
- 7.5%, appropriate for state-regulated utilities with Allowance for Funds Used During Construction, AFUDC, financing with access to loan guarantees and production tax credits; and
- 10%, appropriate for utilities in deregulated markets without access to loan-guaranteed financing or production tax credits.

The real weighted average cost of capital, **r**, will be set equal to each of these rates (3%, 5%, 7.5%, and 10%) for both nuclear and fossil-fired forms of electricity generation. Sensitivity analysis will be performed to determine the influence of the cost of capital on levelized costs.

To understand the relationship between the cost of capital, construction lead time, and compounding Interest During Construction, IDC, consider capital construction expenditures, discounted to the beginning of commercial operation, i.e., when sales and revenues start:

$$IDC = \Sigma\ CX_t \cdot OC\ [(1 + \mathbf{m})^{-t} - 1], \quad t = -lt, \ldots, 0 \tag{2.1.1}$$

where (1) the CX_t are construction expenditure percentages of overnight cost, *OC*, in month *t*, and (2) **m** the monthly weighted average cost of capital during construction, $(1 + \mathbf{m}) = (1 + \mathbf{r})^{1/12}$. In addition, the IDC factor, **idc**, is the percentage add-on for financing charges. Because IDC depends on the construction expenditure rate (how much is spent in each month), Equation (2.1.1) can be complicated because the expenditure rate is not the same over the construction period with smaller amounts being spent early to prepare the site, larger amounts being spent on equipment in the middle of the project, and smaller amounts being spent at the end on instrumentation, training, and fuel loading. For probability analysis, what is required is to calculate the percentage increase in the overnight cost due to project financing, equal to the IDC factor, as a transparent function of construction lead time and the cost of capital.

Equation (2.1.1) becomes a straightforward calculation if the construction expenditures have a uniform distribution, such that $CX_t = 1 / lt$: total overnight cost divided by construction lead time, *lt*. Then Equation (2.1.1) can be approximated (Rothwell, 2011, p. 35) as

$$IDC \cong \mathbf{idc} \cdot OC, \quad \text{where} \tag{2.1.2}$$

$$\mathbf{idc} = [(\mathbf{m} / 2) \cdot lt\,] + [(\mathbf{m}^2 / 6) \cdot lt^2] \tag{2.1.3}$$

The **idc** factor is a function of a parameter, **m**, and a random variable, lead time, *lt*. The random variable, *lt*, is modeled by fitting construction lead time data for recently completed units from IAEA (2013). Because it is unlikely that the distribution of lead times for new nuclear plants is symmetric, the exponential distribution is more suitable to mimic lead time probabilities:

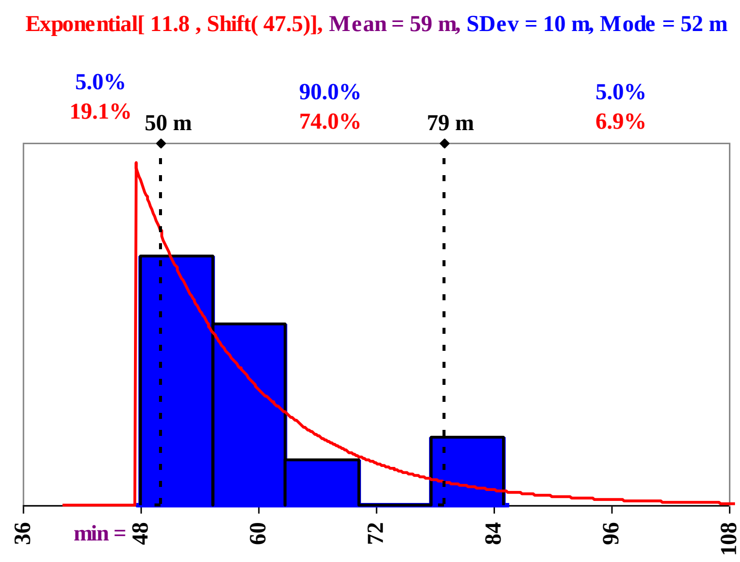
$$\text{Exponential density:} \quad \mathbf{expo(b)} = [\exp(-x / \mathbf{b})] / \mathbf{b}\,, \tag{2.1.4a}$$

$$\text{Exponential distribution:} \quad \mathbf{EXPO(b)} = 1 - \exp(-x / \mathbf{b})\,, \tag{2.1.4b}$$

where ***b*** and *x* must be greater than 0 (thus avoiding negative lead times in simulation), and ***b*** is equal to the mean and the standard deviation. Figure 2.1.1 presents construction lead time data in months fit to an exponential distribution. Because there is only one parameter in this distribution, a shift parameter is introduced to move the origin away from 0 months, this shift is added to ***b***, yielding an expected mean of 59.26 months (= 11.75 + 47.51) or almost 5 years. Using this distribution implies that the construction lead time cannot be less than about 4 years, but could be greater than 10 years: there is no upper limit on construction lead time. (In the figures, blue represents input data, red represents probability densities, and purple represents both.)

It is assumed that the construction lead time for an SMR (Section 2.4) is one-half to two-thirds of that of an ALWR, i.e., an exponential distribution with a mean between 30 and 40 months with a standard deviation of 8 months. The Interest During Construction, **idc**, factor is simulated as in Equation (2.1.3). (Lead time only influences the **idc** factor in the model; overnight cost does not depend on the lead time, although Rothwell, 1986, found that construction cost was positively correlated with the construction lead time.)

Figure 2.1.1: ALWR Construction Lead Time in Months, Fitted to Exponential Density



Source: IAEA (2013) http://www-pub.iaea.org/MTCD/Publications/PDF/rds2-33_web.pdf

Section 2.2: New Nuclear Power Plant Construction Cost Contingency

Traditionally, cost contingency estimation relied heavily on expert judgment based on various cost-engineering standards. Lorance and Wendling (1999, p. 7) discuss expected accuracy ranges for cost estimates: "The estimate meets the specified quality requirements if the expected accuracy ranges are achieved. This can be determined by selecting the values at the 10% and 90% points of the distribution." With symmetric distributions, this infers that 80% of the cost estimate's probability distribution is between the bounds of the accuracy range: ± *X*%.

To better understand confidence intervals and accuracy ranges, consider the normal ("bell-shaped") probability distribution in Figure 2.2.1. The normal distribution can be described by its mean (the expected cost) represented mathematically as E(*cost*), and its standard deviation, a measure of the cost estimate uncertainty. The normal distribution is symmetric, i.e., it is equally likely that the final cost will be above or below the expected cost, so the mean equals the median (half the probability is above the median and half is below) and the mean equals the mode (the most likely cost). The normal density is

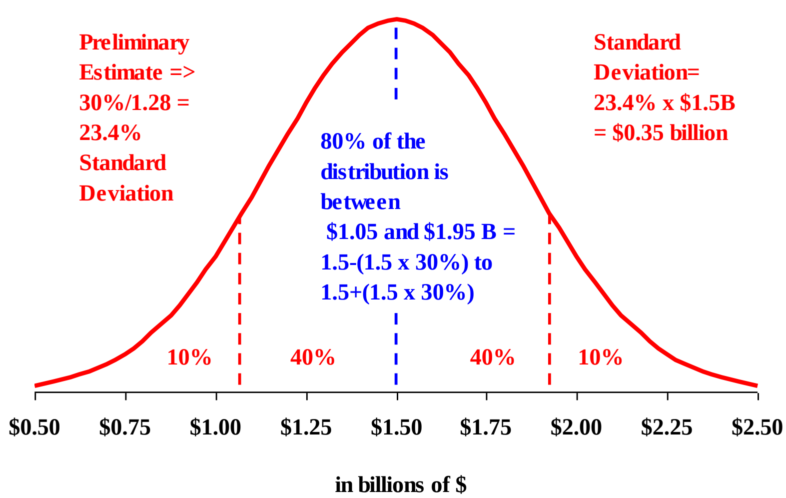
$$\mathbf{normal}(\boldsymbol{\mu}, \boldsymbol{\sigma}) = (2\,\pi\,\boldsymbol{\sigma}^2)^{-½} \cdot \exp\{-(1/2)\cdot(x-\boldsymbol{\mu})^2/\boldsymbol{\sigma}^2\}, \tag{2.2.1}$$

where $\boldsymbol{\mu}$ is the mean (arithmetic average), $\boldsymbol{\sigma}^2$ is the variance, and $\boldsymbol{\sigma}$ is the standard deviation.

Figure 2.2.1 shows the normal density of a cost estimate with a mean, median, and mode of $1.5 billion and a standard deviation of 23.4%: 10% of the distribution is below $1.05B and 10% is above $1.95B, yielding an 80% confidence level.

Figure 2.2.1: A Generic Cost Estimate as a Normal Density

Normal ($1.5 B, $0.35 B), Mean = $1.5 B, SDev = 23.4% = $350 M

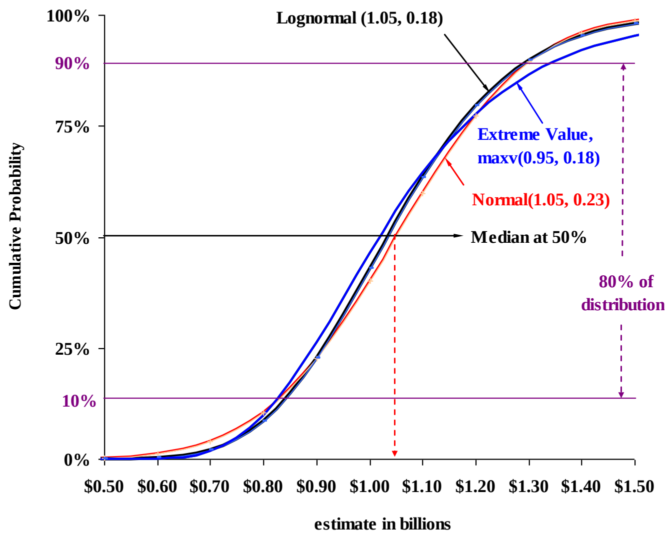


The cumulative distribution of the normal density, i.e., the normal distribution function, **NORMAL**(μ, σ), (which the *integral* of the area under the continuous red line in Figure 2.2.1) is not available in "closed form," i.e., as a simple, algebraic equation (without integral calculus). The normal distribution function is shown in Figure 2.2.2 with non-symmetric distribution functions: the lognormal and the extreme value, discussed below):

$$\textbf{lognormal}(\mu, \sigma) = x^{-1} (2\,\pi\,\sigma^2)^{-1/2} \cdot \exp\{-(\ln x - \mu)^2 / (2 \cdot \sigma^2)\}, \tag{2.2.2}$$

where μ is the mean and σ^2 is the variance; Johnson, Kotz, and Balkarishnan (1995).

Figure 2.2.2: Normal, Lognormal, and Extreme Value Distributions



If the cost estimate were normally distributed, the standard deviation would be

$$\sigma = X / Z, \tag{2.2.3}$$

where X is the absolute value of the level of accuracy and Z depends on the confidence level. For example, the level of accuracy for a "Preliminary Estimate" is about ±30%. If the cost estimator has an 80% confidence in *this* range of accuracy, Z = 1.28, i.e., 80% of the standard normal distribution is between the mean plus or minus 1.28 times σ. So, σ = (30% / 1.28) = 23.4%, which is in the range of 15-30% suggested in the literature, e.g., EPRI (1993). Also, the level of accuracy for a "Detailed Estimate" is about ±20%. With the same level of confidence, Z = 1.28, σ = 20% / 1.28 = 15.6%, which is in the suggested contingency range of 10-20%. Also, the level of accuracy for a "Final Estimate" is about ±10%. With the same level of confidence, σ = 10% / 1.28 = 7.8%, which is suggested contingency range of 5-10%; see Rothwell (2005).

These guidelines suggest a "rule-of-thumb": *the contingency is approximately equal to the standard deviation of the cost estimate (and vice-versa, that the standard deviation of a cost estimate is approximately equal to the contingency)*:

$$\mathrm{C_{ON}}|_{80\%} \approx \sigma\text{, e.g., } 7.8\%|_{\pm 10\%},\ 15.6\%|_{\pm 20\%},\text{ or } 23.4\%|_{\pm 30\%}\,. \tag{2.2.4}$$

The Appendix (Section A1) discusses the appropriate risk aversion premium to place on the standard deviation of the cost estimate at different levels of confidence in the cost estimate. It finds that one cannot simultaneously determine the level of accuracy of the cost estimate, the level of confidence in the cost estimate, and the level of aversion to the standard deviation of the cost estimate. Therefore, a risk aversion parameter is set to 1.00, and multipliers are applied to σ to account for ranges of accuracy, levels of confidence, and aversion to risk (standard deviation).

Section 2.3: New Nuclear Power Plant Construction Cost

Construction Cost, *KC*, is the total amount spent on construction before any electricity or revenues are generated, as defined in *Cost Estimating Guidelines for Generation IV Nuclear Energy Systems* (EMWG, 2007) developed by the Economic Modeling Working Group of the Generation IV International Forum. *KC* is equal to total overnight construction cost plus contingency and financing costs. To measure these consistently, a set of standard definitions of construction accounts, structures, equipment, and personnel is required. Here, in the Code of Accounts, COA, from EMWG (2007), the total construction cost, *KC*, includes

(1) *DIR*: direct construction costs plus pre-construction costs, such as site preparation;

(2) *INDIR*: the indirect costs;

(3) *OWN*: owners' costs, including some pre-construction costs, such as site licensing, **fee**, including the environmental testing associated with an Early Site Permit and/or the Combined Construction and Operating License;

(4) *SUPP*, Supplemental costs (primarily first core costs; if first fuel core costs are levelized in the cost of fuel, as is done here, *SUPP* can be set to $0/kW);

(5) Contingency is expressed here as a contingency rate, $\mathbf{C_{ON}}$; for example, 15%; and

(6) Interest During Construction, IDC, is expressed as a percentage markup on total overnight costs, (1 + **idc**), which is also known as the "IDC factor."

Indirect costs can be expressed as a percentage markup, **in**, on direct cost: *INDIR* = **in** · *DIR*. The indirect percentage markup, **in**, is set to 10% (EMWG 2007). Second, the owners' costs associated with the development of the site, e.g., US NRC and US EPA licensing fees and site preparation expenses, are set to **fee** = $200 M plus 5% of direct costs (EMWG 2007). There is no indirect on owners' costs.

The sum of these costs is the base overnight construction cost, *BASE*. The term overnight describes what the construction cost would be if money had no time value. Some references define "overnight cost" without contingency, and some references define "overnight cost" with contingency, as does US EIA (2013). To make this distinction, *BASE excludes* contingency and *OC includes* contingency. *OC* plus Interest During Construction, IDC, equals total Construction Cost, *KC*. To summarize (where the subscript *k* refers to ALWRs),

$$OC_k = [DIR_k\,(1.05 + \mathbf{in}) + \mathbf{fee}]\,(1 + \mathbf{C_{ON}}) \text{ or} \tag{2.3.1a}$$

$$DIR_k = (\,[OC_k / (1 + \mathbf{C_{ON}})] - \mathbf{fee}\,) / (1.05 + \mathbf{in}) \tag{2.3.1b}$$

$$KC_k = [DIR_k\,(1.05 + \mathbf{in}) + \mathbf{fee}]\,(1 + \mathbf{C_{ON}})\,(1 + \mathbf{idc}_k) \tag{2.3.2}$$

Concerning current estimates of new nuclear power plant construction costs, there is little publicly available data on expected costs for the nuclear power units under construction. However, there are estimates of total overnight costs for the Westinghouse AP1000s, because two twin AP1000s are under active construction with two more sites being prepared, and a version of the AP1000 is being built as two twin plants in China. There are a few construction cost estimates for twin AP1000s for the U.S.:

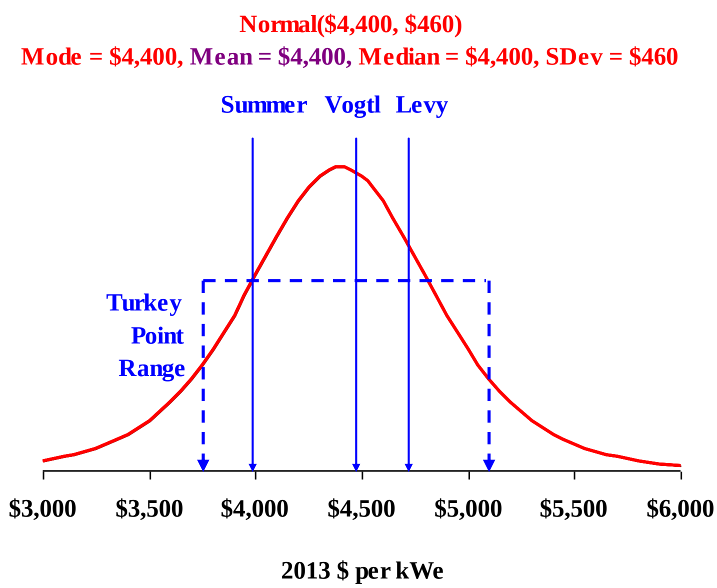
(1) There is the "certified cost" estimate for Vogtle Units 3 & 4: $4,418 M for a 45.7% share of 2,234 MW for Georgia Power (2010, p. 7). The Overnight Cost per kilowatt (including contingency, but not financing) is ($4,418 M/0.457)/(2.234 GW) = $4,330/kW. Updating this from *2010 dollars* to 2013 dollars, yields $4,500/kW. (Although there has been some cost escalation during the construction of Vogtle, there is a conflict as to who will pay this increase; hence the amount of escalation will be unknown until the plant is completed.)

(2) The SCE&G (2010, p. 3) overnight cost estimate for Summer Units 2 & 3 (= $4,270/kW/55%)/(2.234GW) = $3,475/kW in *2007 dollars*, or $3,900/kW in 2013 dollars.

(3) The Progress Energy overnight cost estimate for Levy County Units 1 & 2 is $4,800/kW in 2013 dollars, Progress Energy (2010, pp. 52-56, 132-140, and 320-321).

The average of these cost estimates is $4,400/kW (= $4,500+$3,900+$4,800/3) with a standard deviation of $460; as represented in Figure 2.3.1. In this paper, the baseline for ALWR construction cost is $4,400/kW in 2013 dollars. However, following Section 2.2, an appropriate contingency on overnight costs would be about 10.5% (= $460/$4,400) for 80% confidence, about 13.5% (= 1.29 · $460/$4,400) for 90% confidence, and about 16% (= 1.53 · $460/$4,400) for 95% confidence; see Table A1.1.

Figure 2.3.1: AP1000 Overnight Plant Costs, 2013$/kW, Fitted to a Normal Density



Sources: Georgia Power (2010), SCE&G (2010), Progress Energy (2010), Scroggs (2010)

To measure this uncertainty, there is a cost range for twin AP1000s in regulatory filings associated with Florida Power and Light's Turkey Point Units 6 & 7. Also see Scroggs (2010, p. 45), "Updating the cost estimate range to 2010 dollars, adjusting for the 1,100 MW sized units a net 2.5% escalation rate, results in a cost estimate range of $3,397/kW to $4,940/kW." This cost estimate range is $3,600/kW to $5,300/kW in 2013 dollars with a mid-point of $4,450/kW.

Following cost engineering guidelines (Section 2.2), if this range were expected to cover 95% of the realized Overnight Costs per kilowatt for Levy, the implied standard deviation would be \$430/kW = (\$850/1.96)/kW. The Levy cost estimate mid-point is only 1% different from the baseline here, \$4,450/kW versus \$4,400/kW. Because it is unlikely that the distribution of overnight costs for ALWRs is symmetric, the normal probability density of overnight costs is transformed into an extreme value density:

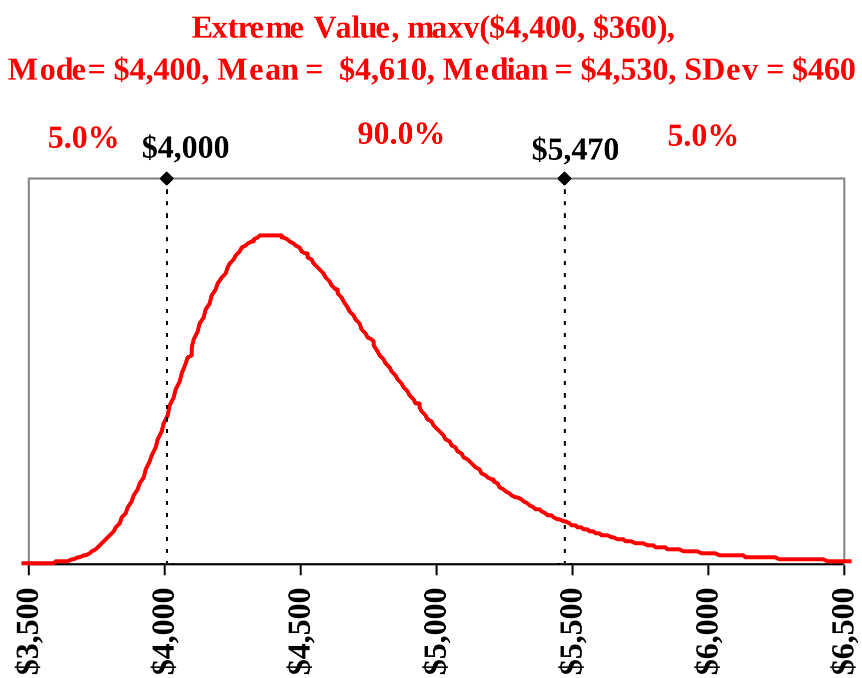
Extreme Value density: $\mathbf{maxv}(\mathbf{a}, \mathbf{b}) = (1/\mathbf{b}) \cdot \mathbf{ab} \cdot \exp\{ (-\,\mathbf{ab}) \}$, (2.3.3a)

Extreme Value distribution: $\mathbf{MAXV}(\mathbf{a}, \mathbf{b}) = \exp\{ -\,\mathbf{ab} \}$, (2.3.3b)

where $\mathbf{ab} = \exp \{ -[(x - \mathbf{a}) / \mathbf{b}] \}$

and ***a*** is equal to the mode, and the standard deviation is equal to ***b*** *times* ($\pi/\sqrt{6}$) ($\approx$ 1.28); Johnson, Kotz, and Balkarishnan (1995). The direction of the skewness in the extreme value distribution can be reversed, such that it has an extreme minimum value. This is designated here as **minv**(**a**, **b**) and **MINV**(**a**, **b**). With an extreme value distribution the expected overnight costs for twin ALWRs are shown in Figure 2.3.2, where the mode is equal to \$4,400/kW, the mean is equal to \$4,610/kW, and the standard deviation is equal to \$460/kW (= \$360 · $\pi/\sqrt{6}$)/kW.

Figure 2.3.2: ALWR Overnight Plant Costs, 2013\$/kW, Fitted to an Extreme Value Density



Source: Figure 2.3.1

Section 2.4: Small Modular Reactors

This section defines Small Modular Reactors, SMRs, as the term is used by the US DOE. In defining modular nuclear technologies, the term "module" has many meanings. The two most common usages of "module" in nuclear energy systems are (1) where equipment is delivered to the site as modules that can be plugged into one another and inserted into a structure with a minimum amount of labor, similar to "plug-and-play" personal computer equipment, and (2) where components and equipment of a nuclear power plant are made under factory quality-control, and delivered in a set of packages that can be assembled on-site, similar to home furniture. Here, (1) a "module" is a piece of pre-assembled equipment, e.g., the "reactor module;" (2) "modular construction" assembles factory-produced, pre-packaged structures on-site; and (3) "on-site construction" relies on site-delivered labor, machines, and materials to build structures and insert modules.

One or more SMR units make up an SMR plant. How unit costs change with reactor size is referred to as "scale economies" and can be represented with a scale parameter, **S**, such that cost *declines* (or increases) by (1 – **S**) for each *doubling* (or halving) of reactor capacity. For example, if **S** = 90%, then a 500 MW reactor would be 10% more costly than a 1,000 MW reactor, and a 250 MW reactor would be 23% more costly than a 1,000 MW reactor (from the same manufacturer) due to scale economies in reactor design of the same technology. (While there could be scale economies in the overnight cost of nuclear steam supply systems, because larger plants take longer to build, scale economies have not been detectable in total construction cost for nuclear power plants above 600 MW; Rothwell 1986.)

In Section 2.7, construction and levelized costs of twin 180 MW SMRs (the mPower design) are derived from construction and levelized costs of twin 1,117 ALWRs (the Westinghouse AP1000 design), assuming scale economies in reactor size, i.e., the larger the SMR, the lower the cost per kilowatt. (This analysis was easier when Westinghouse was actively working on an SMR and one could assume that the ALWR and SMR would be designed and built by the same manufacturer. So the scale relationship between reactors from different suppliers is only approximate.) On the other hand, transportation modes (e.g., rail cars) limit the size of the modules that can be shipped to a generic site. The stated sizes of the SMR reactor modules will vary as the designers minimize construction and other costs subject to manufacturing and transportation constraints.

To begin, the direct construction cost of a smaller reactor, DIR_{SMR}, can be related to the cost for a larger reactor, DIR_{ALWR}, through set of multipliers, including a scale factor:

$$DIR_{\mathrm{SMR}} = DIR_{\mathrm{ALWR}}\,(\mathrm{MW_{SMR}} / \mathrm{MW_{ALWR}}) \cdot \mathbf{S}^{\,(\ln \mathrm{MWSMR} - \ln \mathrm{MWALWR}) / \ln 2}, \qquad (2.4.1)$$

where DIR_{ALWR} is from Equation (2.3.1b) and **S** is the scaling factor, e.g., 90%; see discussion of the "scaling law" in NEA (2011, p. 72). Although smaller in scale, SMRs are simpler in design with less equipment, reducing cost. Let **s** represent the factor saved by simplifying equipment in the design of the LWR SMR:

$$DIR_{\mathrm{SMR}} = DIR_{\mathrm{ALWR}}\,(\mathrm{MW_{SMR}} / \mathrm{MW_{ALWR}}) \cdot \mathbf{s} \cdot \mathbf{S}^{\,(\ln \mathrm{MWSMR} - \ln \mathrm{MWALWR}) / \ln 2}. \qquad (2.4.2)$$

where **s** is the percentage reduction in cost associated with design simplification. If **s** were 85% (NEA, 2011, p. 75), direct costs would be 85% of what the costs would be in Equation (2.4.1).

Further, smaller reactors could enjoy economies of mass production (also known as serial economies or series economies, **ser**) over larger reactors, for example, in improved factory quality control, SMR direct costs could be lower than in Equation (2.4.2):

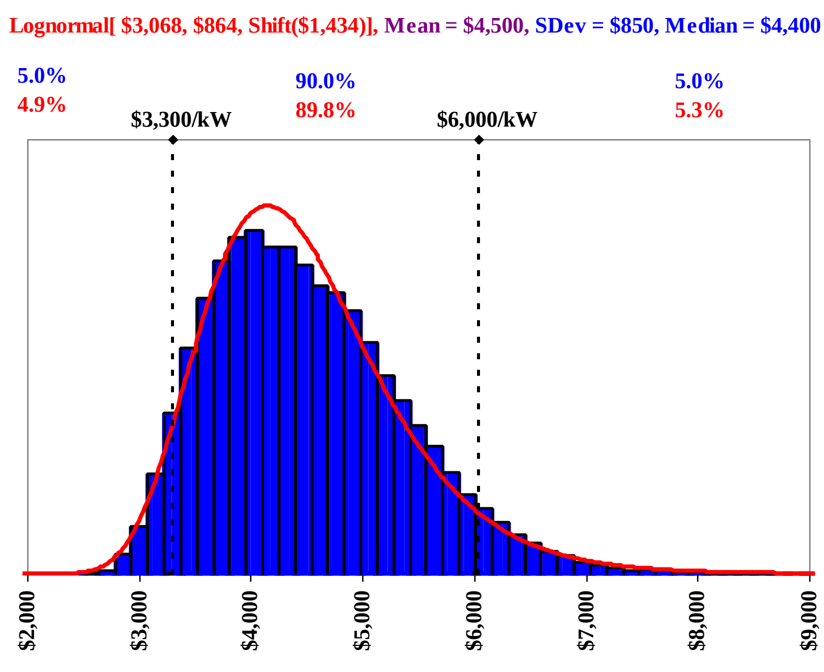
$$DIR_{SMR} = DIR_{ALWR}\,(MW_{SMR}/MW_{ALWR}) \cdot \mathbf{ser} \cdot \mathbf{s} \cdot \mathbf{S}^{\,(\ln MWSMR - \ln MWALWR)/\ln 2}, \qquad (2.4.3)$$

where **ser** is the percentage reduction in cost associated with factory production, e.g., if **ser** were 15%, costs would be 85% of what the costs would be with Equation (2.4.2). In sum, SMR construction costs can be defined by Equation (2.4.3) and Equation (2.4.4):

$$KC_{SMR} = [DIR_{SMR}\,(1.05 + \mathbf{in}_{SMR}) + \mathbf{fee}_{SMR}]\,(1 + \mathbf{C}_{\mathbf{ON}SMR})\,(1 + \mathbf{idc}_{SMR}) \qquad (2.4.4)$$

Uniform probability distributions are assigned to **ser** [80%, 100%], **s** [75%, 95%], and **S** [80%, 100%] to simulate the probability distribution of KC_{SMR}, as shown in Figure 2.4.1. (These parameters together can model most first- and second-order differences between ALWR and SMR costs.)

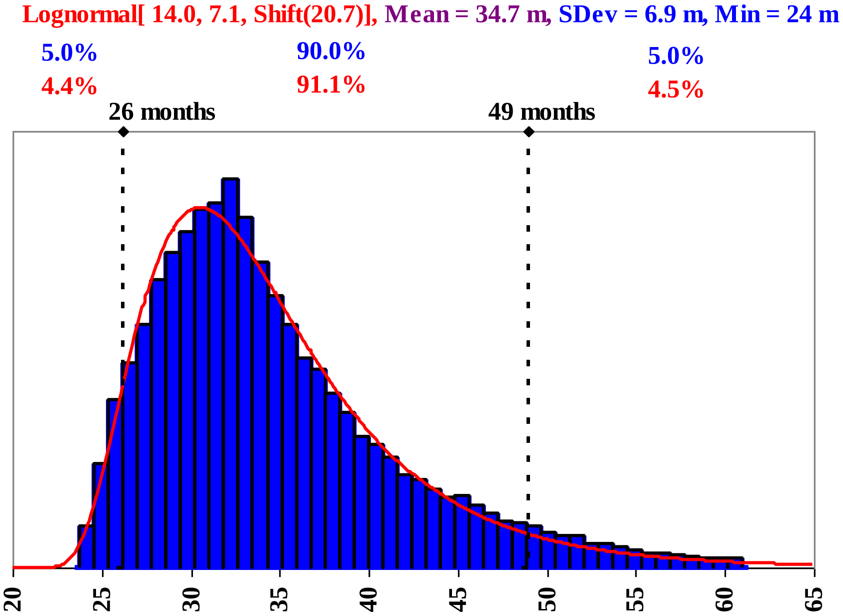
Figure 2.4.1: SMR Plant Overnight Costs 2013$/kW, Simulated, Fitted to a Lognormal Density



Source: Figure 2.3.2, Equations (2.4.3) and (2.4.4) with uniform distributions on **ser, s,** and **S**

Comparing Figure 2.3.2 and Figure 2.4.1 shows that the SMR overnight mean cost per MWh of $4,500/kW is between the mean and mode of the overnight cost of the ALWR, but the standard deviation (at this time) is nearly twice as high: compare the SMR standard deviation of $850/kW versus $460/kW for the ALWR. Also, Figure 2.4.2 presents a SMR construction lead time simulation as a function of the assumptions made in Section 2.1.

Figure 2.4.2: SMR Construction Lead Time, Simulated, Fitted to a Lognormal Density



Source: uniform distribution between 1/2 and 2/3 of those in Figure 2.1.1

Section 2.5: Nuclear Power Fuel Costs

Low Enriched Uranium, LEU, fuel accounting is complex if done precisely, i.e., by considering all lead and lag times of each fuel bundle from the first core through the last core. Here, as in most analyses, the assumption is that fuel is paid in a uniform stream over the life of the plant, without regard to the changing nature of a reactor's set of irradiated fuel. This is similar to the assumption of leasing the fuel from a third party at a per-megawatt-hour fee. However, unlike carbon-fired plants, where fuel is expensed, nuclear fuel is capital that must be paid for over time. The cost of LEU is calculated using the formula from Rothwell (2011, p. 41). This cost includes the costs of natural uranium, conversion to uranium hexafluoride, enrichment, reconversion to uranium oxide, and fuel fabrication.

Figure 2.5.1 presents spot prices of uranium (in 2013 dollars per kilogram of uranium oxide, $/kg-U3O8) and the prices of enrichment, measured in Separative Work Units, SWU, in $/kg-SWU; prices have been converted using the monthly US Producer Price Index through 2013. Uranium prices from 1948 to 1972 are from US DOE (1981), converted to monthly prices by interpolation from mid-year to mid-year; prices from January 1973 through December 2006 are from Bureau of Agricultural and Resource Economics and Sciences (ABARES, 2007). Approximate prices since 2006 have been collected quarterly from the UXC website. For more information on uranium prices, see IAEA-NEA (2012).

In the U.S. market there have been five (illustrative) periods in the history of uranium prices.

Period 1 began in 1948 with purchases by the US Atomic Energy Commission, US AEC.

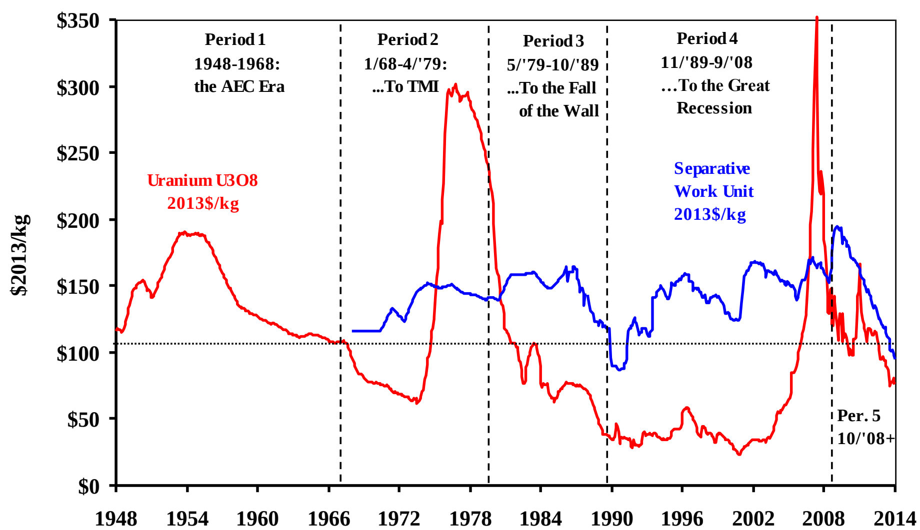
Period 2 began in 1968 with private ownership of uranium in the U.S., but the US AEC maintained a monopoly on enrichment services. During this period, new private owners entered the market with little supply of uranium, driving up the price.

Period 3 began with the accident at Three Mile Island in April 1979, after which nuclear power plants under construction were cancelled and electric utilities left the uranium market; uranium prices fell almost continuously throughout the period; Rothwell (1980).

Period 4 began with the end of the Cold War, symbolically marked by the fall of the Berlin Wall, November 1989, and the entry of nuclear weapons highly enriched uranium into the market. The price of uranium hit historic lows before the possibility of a global nuclear renaissance pushed the price above its 1989 level in late 2003.

Period 5 has been a time of price instability with the end of surplus stockpiles, growth in nuclear power capacity in China and Korea, and the temporary shutdowns of nuclear power plants in Japan following the accident at Fukushima-Dai-Ichi in March 2011.

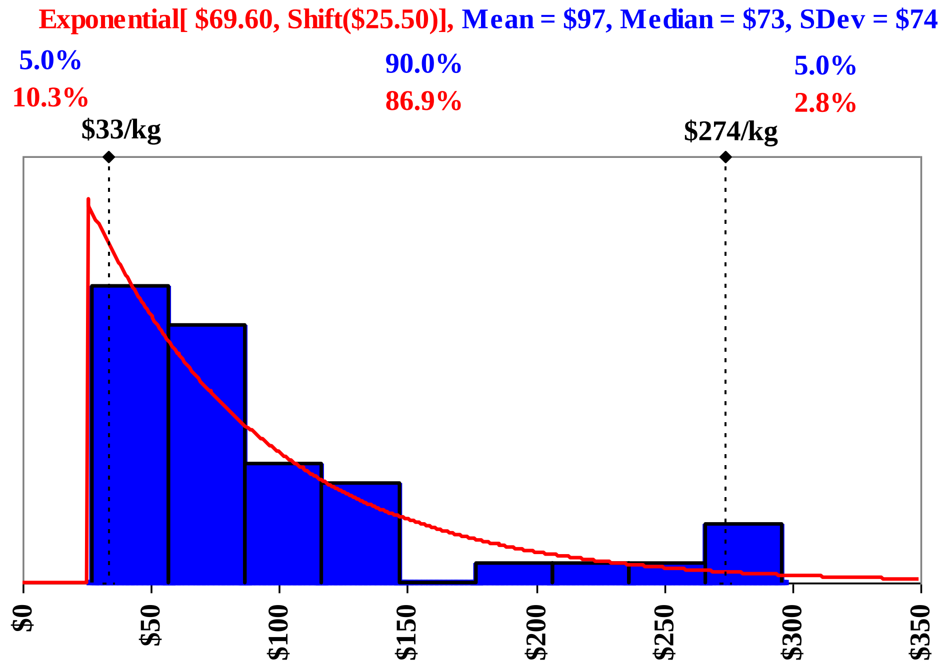
Figure 2.5.1: Natural Uranium and Separative Work Units, SWU, Spot Prices in 2013$/kg



The annual prices of uranium and SWU from 1970 to 2014 were fitted to exponential and extreme value probability densities, respectively. Figure 2.5.2 presents annual uranium data fit to an exponential distribution, thus avoiding negative prices for natural uranium. Because there is only one parameter in this distribution, a shift parameter is introduced to move the origin above $0/kg, this shift is added to ***b***, yielding an expected mean of $95.10/kg-U3O8 (= $69.60/kg + $25.50/kg). This limits values in the simulation of uranium prices to be above $25.50/kg-U3O8.

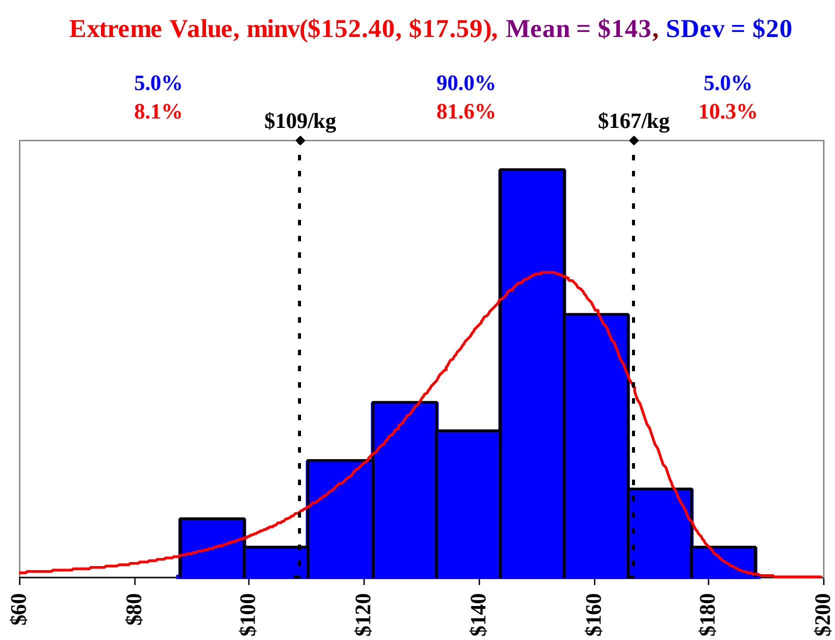
Figure 2.5.3 presents annual Separative Work Unit, SWU, prices fitted to an extreme value (minimum) distribution. While the mean of this distribution is $143/kg based on historic data, the price of Separative Work Units is now below $100/kg with the retirement of diffusion enrichment plants, and it is unlikely to rise above $143/kg (in 2013 dollars) due to excess capacity (particularly in Russia); see Rothwell (2009) and Rothwell (2012).

Figure 2.5.2: Natural Uranium 2013$/kg-U3O8 Prices, Fitted to an Exponential Density



Source: Annualized data from Figure 2.5.1

Figure 2.5.3: SWU 2013$/kg Prices, Fitted to an Extreme Value-Minimum Density



Source: Annualized data from Figure 2.5.1

Table 2.5.1 specifies the baseline parameters for new nuclear fuel. Because of the historic stability, and little impact on the price of LEU, the price to convert U_3O_8 to UF_6 is set at $10/kg and the fuel fabrication price to reconvert the UF_6 to UO_2 (metal) and to fabricate the UO_2 into LEU fuel is set to $300/kg in 2013 dollars from the analysis in Rothwell (2010a). The cost of ALWR fuel is about $2,500/kg and the cost of SMR fuel is about $2,750/kg at a WACC of 7.5% (this rate discounts purchases of uranium and fuel services to the point when it is loaded into the reactor).

There are three primary differences between ALWR and SMR fuel: (1) in U.S. designs SMR fuel is enriched to just less than 5%, an US NRC threshold for Low Enriched Uranium, LEU, so the enrichment is slightly higher for SMRs than for ALWRs, requiring more Separative Work Units, SWU; (2) the burnup (B, in thermal gigawatt-days per tonne of uranium) is lower, e.g., 40 GWd/MTU, compared to 50 GWd/MTU, or higher, for ALWRs; and (3) the efficiency, ε, in converting thermal gigawatts into electrical gigawatts is lower for SMRs, for example, around 30% (here modeled with a uniform distribution between 30% and 33%), compared to around 33% for ALWRs. So, SMRs consume more uranium and SWU per MWh.

Table 2.5.1: Parameters for New Nuclear Fuel Cost Calculations (r = 7.5%)

Levelized Fuel Cost Parameters	ALWR Average	SMR Average	ALWR 2013	SMR 2013
Price of UraniumF6 + Conversion	**$105**	**$105**	**$105**	**$105**
Uranium Enrichment Percentage	4.50%	4.95%	4.50%	4.95%
Price per Separative Work Unit	**$142**	**$142**	**$100**	**$100**
Optimal Tails Assay	0.26%	0.26%	0.22%	0.22%
RU (U input to kgU output)	9.41	10.41	8.76	9.68
Value Function (Feed Assay)	4.87	4.87	4.87	4.87
Value Function (Tails Assay)	5.92	5.92	6.08	6.08
Value Function (Product Assay)	2.78	2.66	2.78	2.66
SWU/kg	6.72	7.65	7.29	8.29
Fuel Fabrication Price, $/kg	$300	$300	$300	$300
Burnup: GWd/MTU	50	40	50	40
Efficiency of MWth to MWe	33.0%	31.5%	33.0%	31.5%
Burnup x Efficiency x 24, MWh/kg-U3O8	396	302	396	302
Fuel Cost/kg	**$2,480**	**$2,750**	**$2,160**	**$2,375**

If the price of SWU were $100/kg-SWU (the price has not been above $100/kg-SWU since 2013), fuel prices for ALWRs would be about $2,160/kg (a reduction of 13%) and fuel prices of SMRs would be about $2,375/kg (a reduction of 14%). Therefore, by maintaining the same methodology of modeling probability distributions for cost drivers based on historic data, *the price of LEU fuel is biased upward* when compared to fossil-fired generators. (Also, back-end costs are assumed to be $0.85/kg for interim storage, see Rothwell, 2010b, and $1/MWh for geologic disposal.)

Section 2.6: Nuclear Power O&M Costs

Next, much has been written about the O&M costs of the currently operating PWRs and BWRs in the U.S. Unfortunately, the best data on nuclear power plant O&M costs are proprietary. Without access to these data, the following model is proposed: Labor, *L*, and Miscellaneous, *M*, costs are often grouped together in nuclear facility costs as Operations and Maintenance, *O&M*, costs where

$$O\&M \quad = \quad (p_L \cdot L) + M \, . \tag{2.6.1}$$

Labor costs, $p_L \cdot L$, are the product of (1) the average employee wages and benefits, and (2) the number of plant employees. Miscellaneous costs, *M*, include maintenance materials, capital additions, supplies, operating fees, property taxes, and insurance. Rothwell (2011, p. 37) estimates values for the amount of labor in Equation (2.6.1) using Ordinary Least Squares, OLS:

$$\ln(L) \quad = \quad \underset{(0.181)}{5.547} + \underset{(0.099)}{0.870}\,(\text{GW})\,, \qquad R^2 = 96\% \quad \text{Standard Error} = 12.43\% \tag{2.6.2}$$

where ln(L) is the natural logarithm of the number of employees and GW is the gigawatt size of the plant. In the semi-log form, the estimated constant is the minimum number of employees, i.e., exp[5.547] = 256 in Equation (2.6.2), and the estimated slope is the growth rate in employees with each GW increase in size. Equation (2.6.2) implies the staffing level for a 360-MW SMR would be about 350, or about 1 employee per MW.

However, there is much less known about the standard error in applying the estimate in Equation (2.6.2) to SMR labor estimation. On the other hand, SMR labor should be lower per MWh than with ALWRs given the reduction in the complexity of the equipment. So, the standard error in simulation is modeled as a truncated normal with $\varepsilon_L < 0$. This reduces the level of employment by (on average) -9.6% (although it varies in simulation).

Assuming that the burdened labor rate, including benefits, p_L, is \$80,000 per employee per year in the U.S. (EMWG, 2007), the cost of fixed labor, *LX*, is

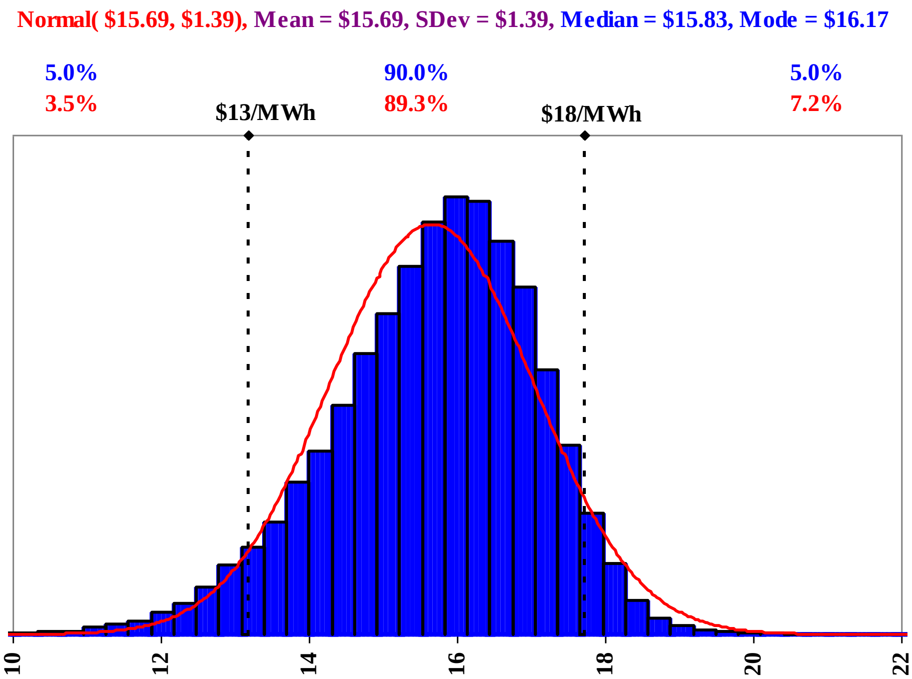
$$p_L \cdot L = p_L \cdot e^{5.55} \cdot e^{0.87\,\text{GW}} = \$80{,}000 \cdot 350 \cdot (1 - 0.096) = \$25\text{ M} \, . \tag{2.6.3}$$

Let the percentage markup, **om**, be 0.65, as in Rothwell (2011, p. 40), then

$$O\&M = (1 + \mathbf{om})\,(p_L \cdot L) = 1.65 \cdot \$25\text{ M} = \$41\text{ M} \, . \tag{2.6.4}$$

(In simulation, **om** varies between 0.55 and 0.75.) Dividing by expected MWh, as a function of the capacity factor (see the next section), the expected O&M cost per MWh is normally distributed with a mean of \$15.69/MWh and a standard deviation of \$1.39/MWh, as shown in Figure 2.6.1, modelled with a normal distribution in which 90% of the observations would be between \$13/MWh and \$18/MWh. These estimates are similar to those in Dominion Energy, Inc., Bechtel Power Corporation, TLG, Inc., and MPR Associates (2004).

Figure 2.6.1: Twin SMR O&M $/MWh, Simulated, Fitted to a Normal Density



Source: Equation (2.6.2) with a truncated normal error and Equation (2.6.4)

Section 2.7: Nuclear Power Capacity Factors

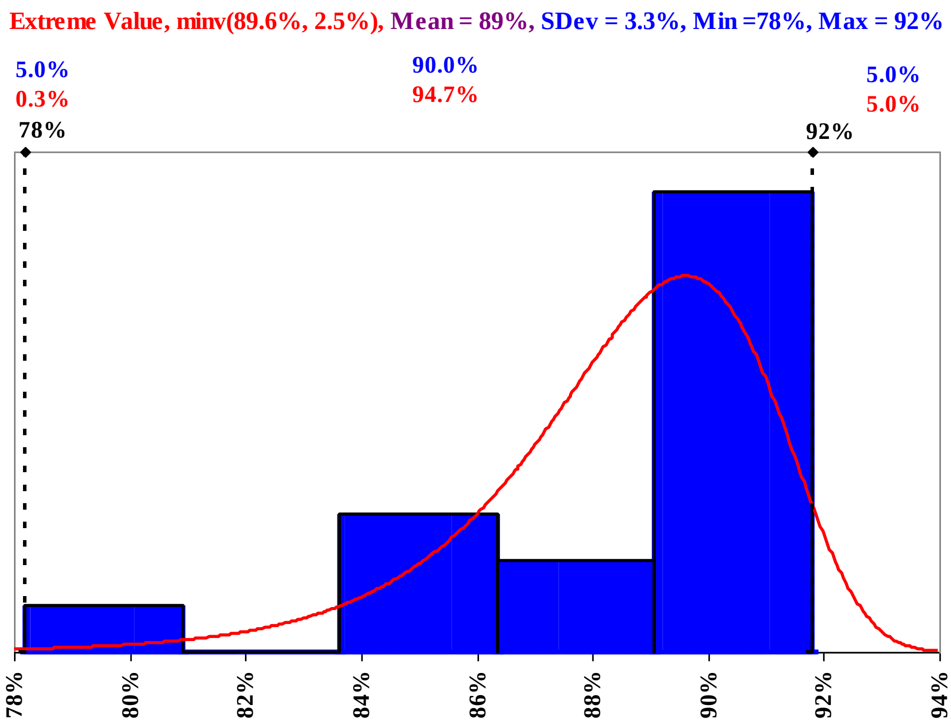
The last random variable to discuss involves the denominator in Equation (1.1.1), as defined in Equation (1.1.3), where annual electrical energy output is a function of the size of the power plant, MW, the number of hours in a year, TT, and a random variable, *CF*, the capacity factor. The US NRC defines several capacity factors, each with a different measure of capacity. In Equation (1.1.3), let *E* be the NRC's "Net Electrical Energy Generated" and MW be the "Net Maximum Dependable Capacity," after subtracting power consumed by the plant itself. This is the most compatible with the IAEA's definition of "Load Factor." There are three related indicators of generating performance: productivity, availability, and reliability. (For a comparison of US NRC and IAEA definitions for these performance indicators, see Rothwell, 1990).

Productivity refers to the ability of the power plant's generating capacity to produce electricity. Productivity is measured by the Capacity Factor, CF_k, for each technology in each period. Let

$$CF_{kt} \equiv E_{kt} / (\mathrm{MW}_{kt} \cdot \mathrm{TT}) . \tag{2.7.1}$$

Figure 2.7.1 presents average annual capacity factors of U.S. nuclear power plants. These data are fitted to an extreme value density function with a mean value of 88.5% and a standard deviation of 2.5% with a minimum of 78.2% and a maximum of 91.8%.

Figure 2.7.1: U.S. Nuclear Power Plant Capacity Factors,
Fitted to an Extreme Minimum Value Density
(annual average for the U.S. fleet of light-water nuclear power plants)



Source: http://www.eia.gov/totalenergy/data/monthly/pdf/sec8.pdf

Section 2.8: New Nuclear Power's Levelized Cost of Electricity

Table 2.8.1 presents parameters in calculating levelized capital costs for new nuclear. (Only Nth-of-a-Kind, NOAK, costs are considered here; on calculating First-of-a-Kind, FOAK, costs, see Rothwell, 2011, pp. 57-61.) (1) The first set of parameters specifies the size of the unit, the plant, and the typical number of units per plant. (2) The second set specifies the percentage allocations of direct construction expenditures for Code of Accounts (COA) 21-25; see EMWG (2007). Because these percentages are assumed the same for both ALWRs and SMRs, the cost of the reactor is the same proportion of direct costs for both technologies. (3) The third set of parameters specifies rates to transform direct costs into overnight costs, where a 15% contingency implies a "Detailed Estimate." (Contingency was included in the observations on costs in Section 2.3, therefore the contingency here is associated with the uncertainty of building the same technology at a different site; note this upwardly biases the cost of construction.) (4) The fourth set of parameters specifies how smaller reactor costs are related through scale economies to larger reactor costs, design simplification, and the possible cost savings from serial production of SMRs. (5) The last set of parameters levelizes capital costs over MWh.

Table 2.8.1: Parameters for New Nuclear Construction Cost Calculations

Levelized Capital Cost Parameters	**SMR Value**
Construction Lead Time in months, *lt*	35
Unit net capacity in MWe	180
Number of units	2
Plant net capacity in MWe, MW	360
COA21: Site Improvements and Structures	20%
COA22: Reactor (and Steam Generator)	40%
COA23: Turbine Generator and Condenser	25%
COA24: Electrical Equipment	10%
COA25: Cooling System and Misc. Equip.	5%
Indirect Rate, **in**	10%
Owners Cost (licensing), **fee**	$200M
Owners Cost (administration), OWN – **fee**	5%
Contingency, $\mathbf{C_{on}}$	15%
Scale Economies Parameter, **S**	90%
Simplified Design Parameter, **s**	85%
Savings from Serial Economies, **ser**	90%
Average Capacity Factor, *CF*	88.5%
Depreciation life (years), T	40

Table 2.8.2 presents expected (deterministic) *construction costs* for SMRs. Table 2.8.3 presents expected (deterministic) *levelized costs* for SMRs for costs of capital of 3%, 5%, 7.5%, and 10%. *At a cost of capital of 7.5%*, the levelized cost of a SMR is estimated to be about $80.29/MWh. This assumes that the design has 15% (1 – **s**) less equipment than would be expected with an ALWR (off-setting the scale "penalty," **S**) and that the manufacturer is able to reduce direct costs by 10% through factory production (1 – **ser**). At a WACC of 5%, levelized costs are about 19% less. At a WACC of 10%, levelized costs are about 21% more. This shows the importance of the cost of capital in determining the competitiveness of SMRs, and hence the importance of understanding uncertainties in SMR construction cost.

Monte Carlo simulations were performed using these parameters and density functions from Section 2.1 to Section 2.7 with the software program @RISK for various costs of capital, Palisade (2013). Figure 2.8.1 presents the resulting simulated levelized cost of electricity for SMRs at a cost of capital of 7.5%, fitted to a lognormal density. With this density the simulated levelized costs of SMRs, LC_{SMR}, cannot be below $35.06/MWh with a mean of $81.04/MWh (= $45.98/MWh + $35.06/MWh), which is $0.75/MWh greater than the deterministic mean, a difference due to the asymmetries in the underlying cost-driver probability distributions. Figure 2.8.2 examines the impact of changes in the cost of capital on the cumulative cost distributions. The next section compares these cost expectations with those of natural gas CCGTs and coal-fired power plants.

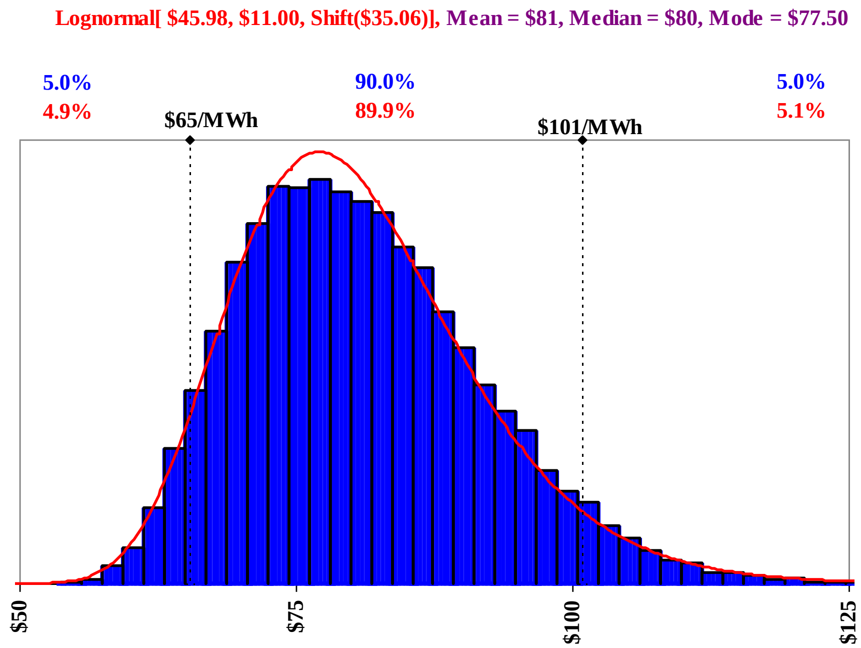
Table 2.8.2: Construction and Operating Costs for SMR (all values in 2013 dollars)

Levelized Construction Cost	**SMR**
Net Electrical Capacity	360
Size of Power Unit	180
Number of Power Units, N	2
Site Improvements and Structures	$172M
Reactor and Steam Generator	$429M
Turbine Generator, and Condenser	$268M
Transformer and Elec. Equipment	$107M
Cooling System and Misc. Equipment	$54M
Direct Costs, DIR, $/kW	$1,031M
Indirect Costs, INDIR, 10%	$103M
Owner's Cost, OWN	$252M
BASE Overnight Cost	$1,385M
Contingency,	$208M
Overnight Cost, OC	$1,593M
Overnight Cost $/kW	$4,426
Interim Storage per MWh	$0.85
Long-Term Disposal per MWh	$1.00
Number of Employees	317
Labor Costs	$25.33M
Insurance + Misc. Costs	$18.47M

Table 2.8.3: Levelized Costs for SMR at WACC of 3%, 5%, 7.5%, and 10%

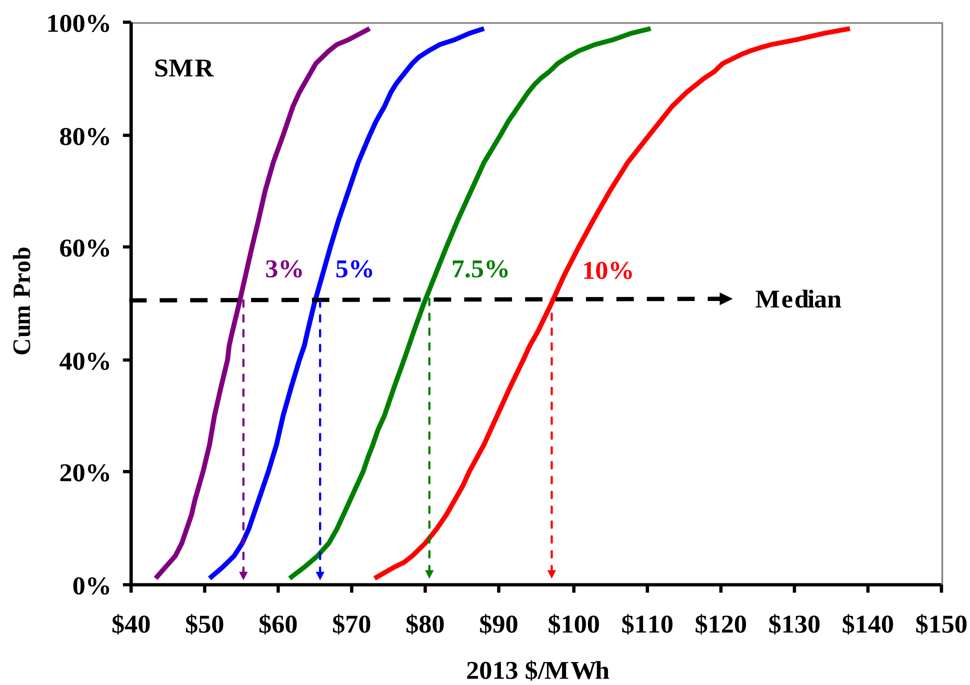
Levelized Capital Cost	**SMR**	**SMR**	**SMR**	**SMR**
Weighted Average Cost of Capital	**3.0%**	**5.0%**	**7.5%**	**10.0%**
Interest During Construction factor	4.4%	7.4%	11.3%	15.2%
Interest During Construction, IDC	$71M	$119M	$180M	$242M
KC, Total Construction Costs	$1,664M	$1,712M	$1,773M	$1,835M
KC ($/kW)	$4,622	$4,755	$4,925	$5,098
Annual D&D Contribution	$5.52M	$5.68M	$5.88M	$6.09M
Fuel Cost ($/kg)	$2,586	$2,657	$2,750	$2,836
Fuel Cost per MWh	$9.66	$9.92	$10.26	$10.59
Levelized Capital Cost + D&D Cost	**$27.74**	**$37.75**	**$52.50**	**69.37**
Levelized O&M Costs	**$15.68**	**$15.68**	**$15.68**	**$15.68**
Levelized Fuel Cost + Waste Fees	**$11.51**	**$11.77**	**$12.11**	**$12.44**
LC, Levelized Cost	**$54.93**	**$65.20**	**$80.29**	**$97.49**

Figure 2.8.1: SMR Levelized Cost, Simulated, Fitted to a Lognormal Density (r = 7.5%)



Source: Figures 2.4.1, 2.4.2, 2.5.2, 2.5.3, 2.6.1, and 2.7.1, and Tables 2.5.1 and 2.8.1

Figure 2.8.2: SMR Levelized Cost, Simulated Cumulative Distributions (r = 3%, 5%, 7.5%, and 10%)



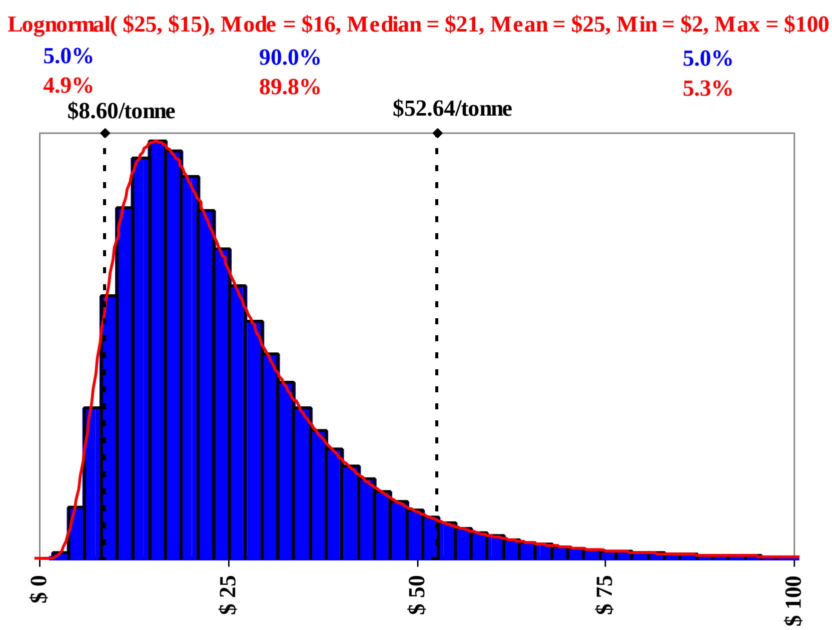
Source: Figure 2.8.1 and Tables 2.8.2 and 2.8.3

Section 3: The Levelized Cost of Electricity of Fossil-Fired Generators

Section 3 models the levelized cost of electricity for fossil-fired power plants based on US Energy Information Administration, EIA, generation cost assumptions and EIA price data. Two issues must be discussed before assessing fossil-fired electricity generators: (1) the price and cost of a tonne of carbon dioxide, and (2) the capacity factor of the generating units.

First, MIT (2009) assumed a CO_2 fee of $25 per metric tonne of CO_2, tCO_2, as in most U.S. energy-economic analyses during the past decade (due to early empirical experience with the European Union Emissions Trading Scheme "cap-and-trade" market before the financial crisis of 2008). But the cost of CO_2 (as opposed to the price of CO_2) is unknown. Therefore, it is modeled with a wide (and skewed) probability distribution: **lognormal($25, $15)**. Figure 3.1.1 presents this density: 90% of the time the cost of (or damages from) tCO_2 could be between $8.60/$tCO_2$ and $52.64/$tCO_2$, with 99% above $1.55/$tCO_2$ and 99% below $77.88/$tCO_2$ (in 500,000 iterations).

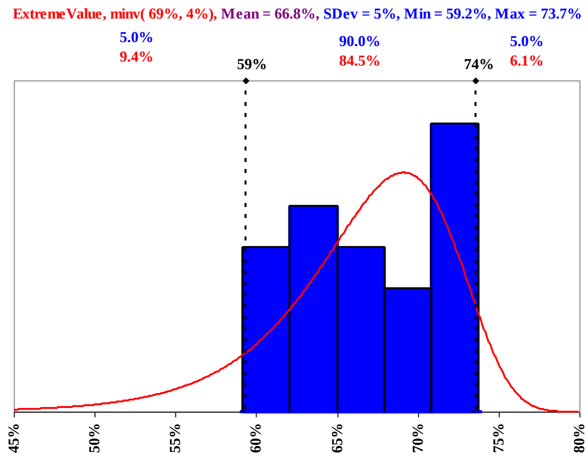
Figure 3.1.1: CO_2 $/tonne Cost, Simulated with Lognormal Density



Source: $25 mean from MIT(2009) with lognormal density and SDev = $15, compare with Nordhaus (2011) Figure 5

Second, while capacity factors for nuclear power plants are easy to find and easy to interpret, it is because most U.S. plants are running as base-load, are approximately the same size, and approximately the same vintage, this is not the case in natural gas and coal plants. In EIA database, there are no capacity factors calculated specifically for CCGTs and there are no capacity factors calculated for old and new coal plants. Figure 3.1.2 presents the capacity factors for base-load coal plants fitted to an extreme value function. These are employed in simulation of both coal and natural gas capacity factors.

Figure 3.1.2: U.S. Fossil-Fired Plant Capacity Factors, Fitted to an Extreme Minimum Value Density



Source: http://www.eia.gov/totalenergy/reports.cfm?t=182

Section 3.1: The Levelized Cost of Electricity of Natural Gas CCGTs

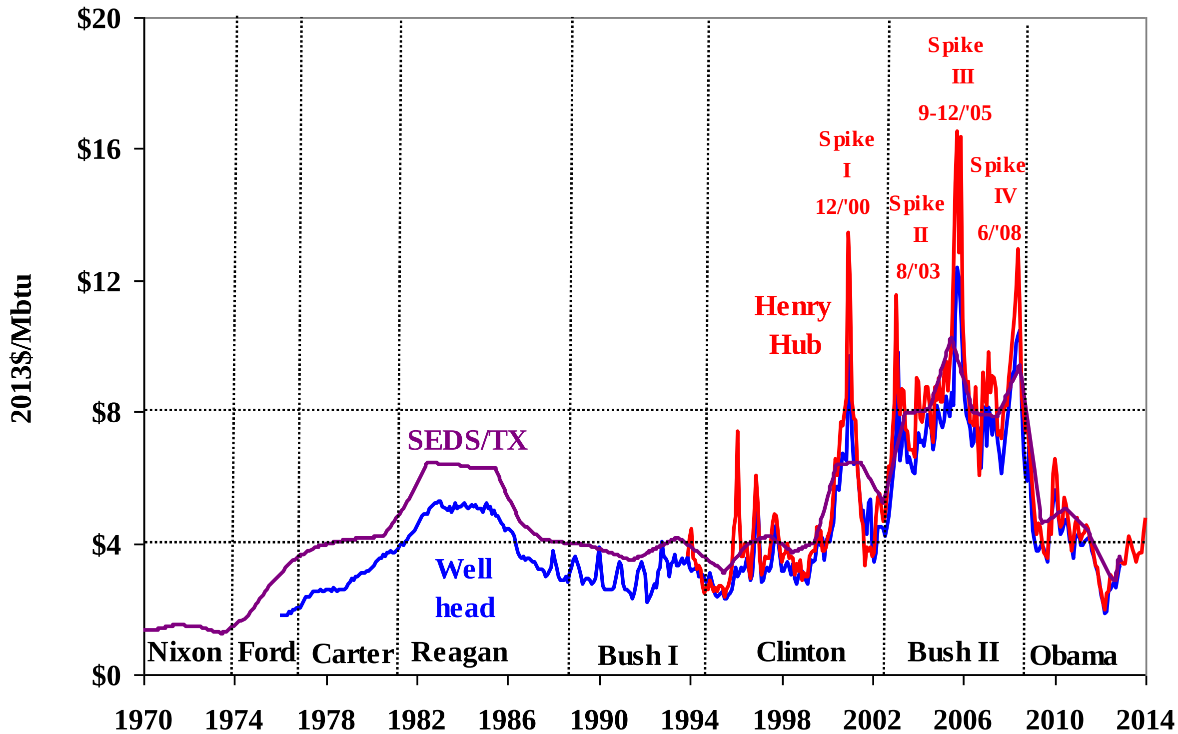
Table 3.1.1 presents costs for CCGTs from US EIA's "Assumptions to the *Annual Energy Outlook*" (2009−2013) and MIT (2009). The first column gives the reference where EIA data can be found (*AEO* refers to the *Annual Energy Outlook*, published each year by the US Energy Information Administration, see, for example, US EIA 2013). The cost data are given in real dollars of the year indicated, which is usually two years before the publication date of the *AEO*. Since 1995, the EIA has reported 400 MW as a standard size of an "advanced gas/oil combined cycle," CCGT. However, MIT (2009) assumes a 1,000 MW CCGT to be compatible with the size of a single nuclear power unit and a coal plant in its analysis. The lead time, LT (in years) is compatible with the IAEA standard of defining the construction period from the time of first concrete to commercial operation. The next four columns give overnight (from the *AEO* in the dollars of the year indicated and in 2013 dollars), variable, and fixed costs for CCGTs. The last column gives the heat rate in British thermal units (btu) per kilowatt-hour. However, there are no assumed fuel prices in EIA *AEO*. Fuel prices are determined by the National Energy Modeling System, NEMS, which equilibrates all energy prices and markets based on the *AEO* assumptions.

Table 3.1.1: US EIA Annual Energy Outlook Assumptions for NEMS, CCGT

Source: EIA, "Assumptions for the …"	Year Dollars $	CCGT Size MW	CC GT LT y	CCGT *OC* $/kW	CCGT *OC* 2013$/kW	CCGT Variable 2013$ /MWh	CCGT Fixed 2013$ /kW	CCGT Heat Rate BTU/kWh
AEO 2009, Table 8.2	2007	400	3	$947	$1,079	$2.28	$13.33	6,752
AEO 2010, Table 8.2	2008	400	3	$968	$1,059	$2.23	$13.09	6,752
AEO 2011, Table 8.2	2009	400	3	$917	$972	$3.26	$15.31	6,333
AEO 2012, Table 8.2	2010	400	3	$1,003	$1,055	$3.27	$15.37	6,430
AEO 2013, Table 8.2	2011	400	3	$1,006	$1,037	$3.31	$15.55	6,333
MIT (2009, p. 18-22)	2007	1,000	2	$850	$968	$0.47	$26.20	6,800

To forecast fuel prices, Figure 3.1.3 presents three natural gas price series: (1) interpolated monthly Texas natural gas prices (from annual data) *for electric utilities* from 1970 to 2012 from the US EIA's "State Energy Data System," SEDS; (2) the monthly U.S. natural gas "wellhead price" from 1977-2014; and (3) monthly "Henry Hub" spot market prices in Louisiana from 1994−2014. Figure 3.1.3 shows the natural gas market experienced at least four price spikes in the last decade. (Prices to electric utilities are a few dollars higher than wellhead and Henry Hub prices due to transmission charges.) Figure 3.1.4 presents a histogram and fitted probability density for the SEDS/TX prices in Figure 3.1.3. The data and the density show a skewed distribution with a mode of $3.68/Mbtu, a median of $4.34/Mbtu, and a mean of $4.71/Mbtu with a standard deviation of $2.25/Mbtu.

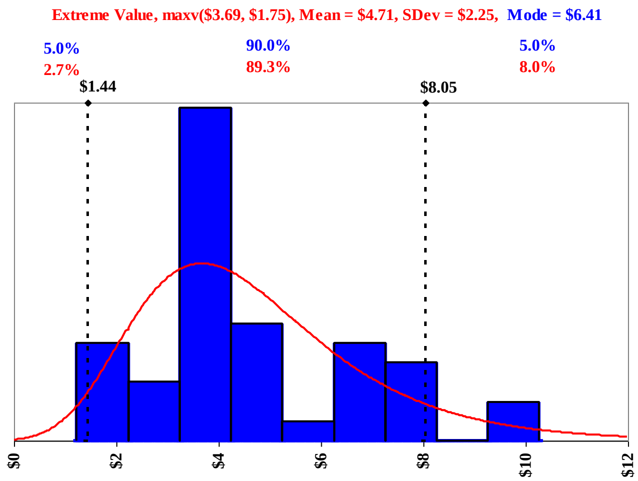
Figure 3.1.3: Natural Gas Prices, 2013$/Mbtu, 1970−2014



Sources: http://www.eia.gov/state/seds/seds-data-fuel.cfm?sid=US; http://www.eia.gov/dnav/ng/hist/n9190us3m.htm; and http://research.stlouisfed.org/fred2/series/GASPRICE/downloaddata?cid=98

Table 3.1.4 presents the calculation of levelized cost for natural-gas-fired electricity assuming costs of capital of 3%, 5%, 7.5%, and 10% compared with MIT (2009) updated to 2013 dollars. (Entries with probability densities are in italic.) In addition, in Table 3.1.2 the price of natural gas was increased from the assumed value in MIT (2009) of $3.50/Mbtu in 2007 dollars to $4.27/Mbtu in 2013 dollars (see last column). The second to last column shows LC_{CCGT} for the MIT model assuming the same average fuel price in the middle columns of Table 3.1.4. Also, the capacity factor for CCGTs is assumed to be equal to that of base-loaded coal plants, as discussed above.

Figure 3.1.4: Texas Electric Utility Natural Gas Prices, SEDS 1970−2012, Fitted to an Extreme Value Density



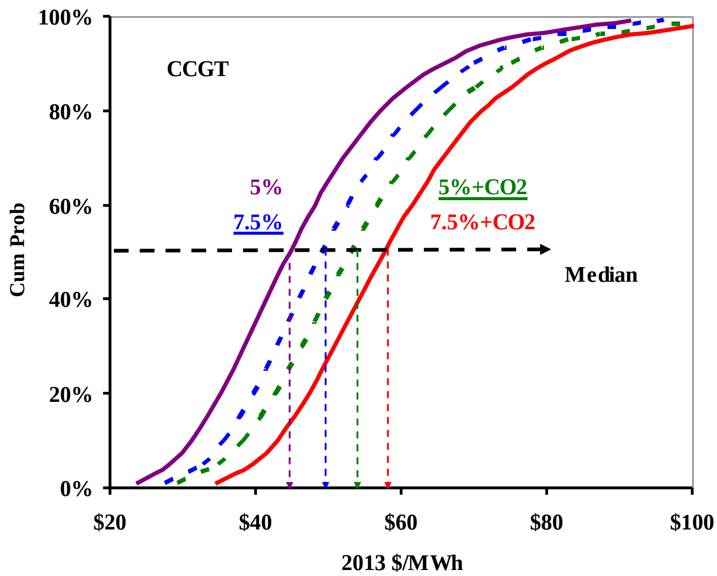
Sources: http://www.eia.gov/state/seds/seds-data-fuel.cfm?sid=US;

Table 3.1.2: Levelized Cost for New Natural Gas Generation (2013 dollars)

Combined Cycle Gas Turbine (CCGT)		**(1)**	**(2)**	**(3)**	**(4)**	**MIT**	**MIT**
Levelized Cost		**CCGT**	**CCGT**	**CCGT**	**CCGT**	**CCGT**	**CCGT**
All values in 2013 dollars	**r =**	**3.0%**	**5.0%**	**7.5%**	**10.0%**	**7.8%**	**7.8%**
Net Electrical Capacity	MWe	400	400	400	400	1,000	1,000
Average Capacity Factor	%	***67%***	***67%***	***67%***	***67%***	**85%**	**85%**
Plant depreciation life	Years	40	40	40	40	40	40
Construction Lead Time	Years	3	3	3	3	2	2
Base Overnight Cost	$/kw	$960	$960	$960	$960	$896	$896
Contingency (from EIA)	%	8%	8%	8%	8%	8%	8%
Total Overnight Cost	$/kw	$1,037	$1,037	$1,037	$1,037	$968	$968
Interest During Construction factor	%	4.4%	7.5%	11.3%	15.2%	7.55%	7.55%
KC per kW with IDC	$/kw	$1,083	$1,114	$1,154	$1,195	$968	$968
KC, Total Capital Investment Cost	$ M	$433	$446	$462	$478	$968	$968
Fuel Price ($/GJ = 0.948 x $/Mbtu)	$/M BTU	***$4.71***	***$4.71***	***$4.71***	***$4.71***	**$4.71**	**$4.27**
CO2 Price ($/tonne)	$/tonne	***$25.00***	***$25.00***	***$25.00***	***$25.00***	**$25.00**	**$25.00**
CO2 per MWh ("carbon intensity factor")	t/MWh	0.336	0.336	0.336	0.336	0.361	0.361
Heat Rate (from EIA, 2013)	BTU/kWh	6,333	6,333	6,333	6,333	6,800	6,800
Variable O&M	$/MWh	$3.31	$3.31	$3.31	$3.31	$0.47	$0.47
Fixed O&M + Incremental Capital Costs	$/kW	$15.55	$15.55	$15.55	$15.55	$26.20	$26.20
Levelized Capital Cost	$/MWh	$8.01	$11.10	$15.67	$20.89	$10.66	$10.66
Levelized O&M Cost	$/MWh	$5.97	$5.97	$5.97	$5.97	$3.99	$3.99
Levelized Fuel Cost	$/MWh	$29.80	$29.80	$29.80	$29.80	$32.00	$29.04
Levelized Fuel CO2 Cost	$/MWh	$8.41	$8.41	$8.41	$8.41	$9.03	$9.03
Levelized Cost without CO2 cost	**$/MWh**	**$43.78**	**$46.87**	**$51.43**	**$56.65**	**$46.64**	**$43.68**
Levelized Cost with CO2 cost	**$/MWh**	**$52.18**	**$55.27**	**$59.84**	**$65.06**	**$55.67**	**$52.71**

For natural gas CCGT, Figure 3.1.5 presents the cumulative probability distributions for Monte Carlo simulations without and with a $25/t$CO_2$ fee at real costs of capital of 5% and 7.5%. Because of the high number of price spikes in the natural gas price data, the cumulative (extreme value) distributions for LC_{CCGT} have long tails.

Figure 3.1.5: CCGT Levelized Cost, Simulated Cumulative Distributions (r = 5%, 7.5%)



Sources: Figures 3.1.1, 3.1.2, 3.1.4, and Table 3.1.2

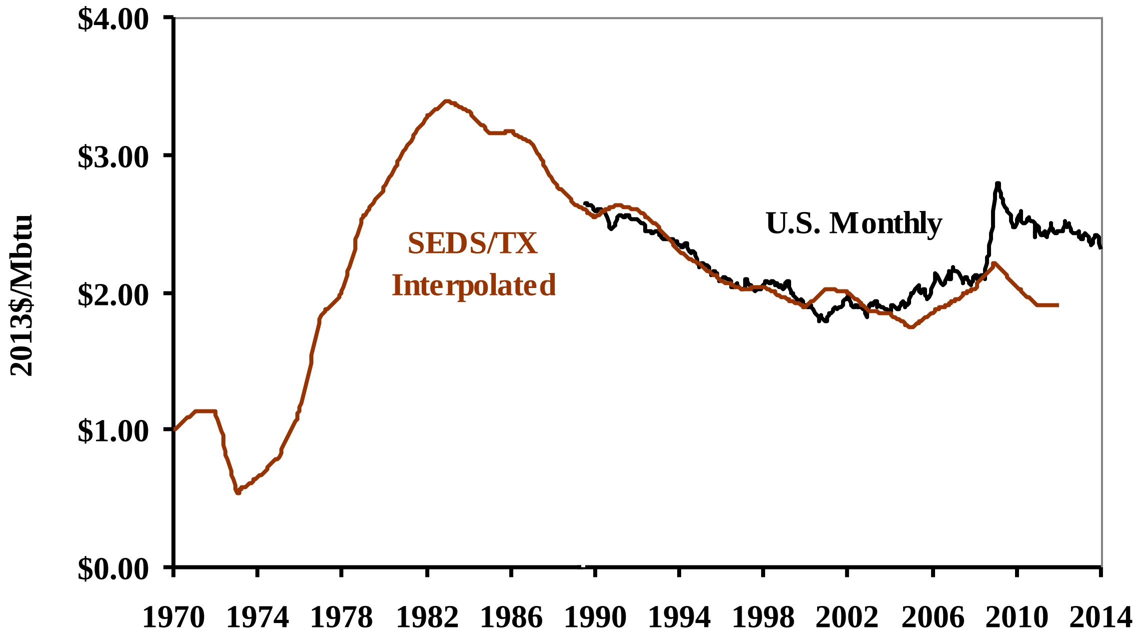
Section 3.2: The Levelized Cost of Electricity of Coal-Fired Steam Turbines

Table 3.2.1 presents coal-fired power plant costs from US EIA's "Assumptions to the Annual Energy Outlook" and coal assumptions and costs from MIT (2009). (See discussion of Table 3.1.1 for definitions.) Figure 3.2.1 presents delivered coal price data from (1) the US EIA's "State Energy Data System" from 1970-2012, and (2) monthly U.S. average monthly sub-bituminous coal from 1990-2014. Figure 3.2.2 presents a histogram and fitted probability density for the SEDS/TX annual prices from Figure 3.2.1. The data and the density show a skewed distribution with a mode of $1.90/Mbtu, a median of $2.03/Mbtu, and a mean of $2.13/Mbtu with a standard deviation of $0.93/Mbtu.

Table 3.2.1: US EIA Annual Energy Outlook Assumptions for NEMS, Coal, 2013 dollars

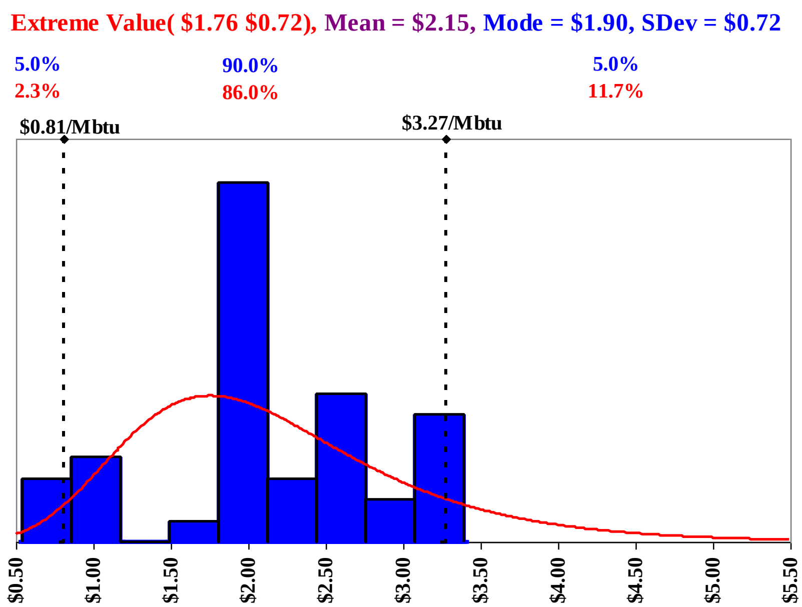
Source: EIA, "Assumptions for the …"	Year Dollars $	Coal Size MW	Coal LT y	Coal *OC* $/kWe	Coal *OC* 2013$/kWe	Coal Variable 2013$ /kW	Coal Fixed 2013$ /kW	Coal Heat Rate BTU/kWh
AEO 2009, Table 8.2	2007	600	4	$2,058	$2,344	$5.23	$31.36	9,200
AEO 2010, Table 8.2	2008	600	4	$2,223	$2,433	$5.13	$30.80	9,200
AEO 2011, Table 8.2	2009	1,300	4	$2,809	$2,979	$4.45	$31.08	8,740
AEO 2012, Table 8.2	2010	1,300	4	$2,844	$2,991	$4.47	$31.20	8,800
AEO 2013, Table 8.2	2011	1,300	4	$2,883	$2,969	$4.52	$31.56	8,740
MIT (2009, p. 18-22)	2007	1,000	4	$2,300	$2,620	$4.07	$58.09	8,870

Figure 3.2.1: Interpolated Texas and U.S. Coal Prices, 2013 dollars/Mbtu, 1970−2014



Sources: http://www.eia.gov/state/seds/seds-data-fuel.cfm?sid=US
http://www.eia.gov/electricity/monthly/pdf/epm.pdf

Figure 3.2.2: Texas Electric Utility Coal Prices, SEDS 1970−2012, Fitted to an Extreme Value Density



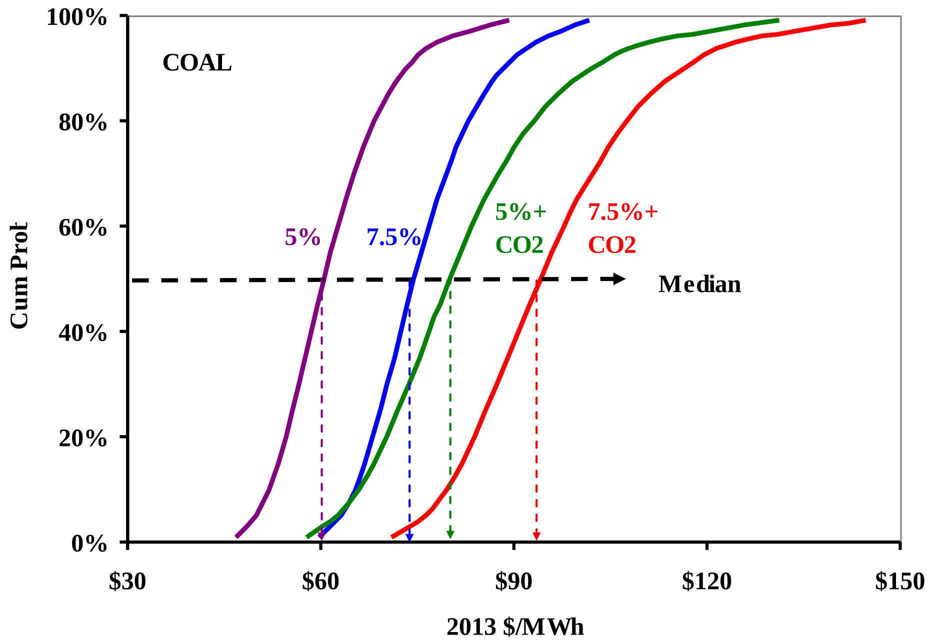
Sources: http://www.eia.gov/state/seds/seds-data-fuel.cfm?sid=US

Table 3.2.2 presents the calculation of levelized cost for coal-fired electricity assuming costs of capital of 3%, 5%, 7.5%, and 10% compared with MIT (2009) updated to 2013 dollars. Simulating the price of coal, Figure 3.2.3 presents the cumulative probability distributions with and without a $25/t$CO_2$ fee with a real cost of capital of 7.5%. These coal-fired levelized cost probability distributions are compared with those for SMRs and CCGTs in Figure 3.2.4.

Table 3.2.2: Real Levelized Cost for New Coal-Fired Generation (2013 dollars)

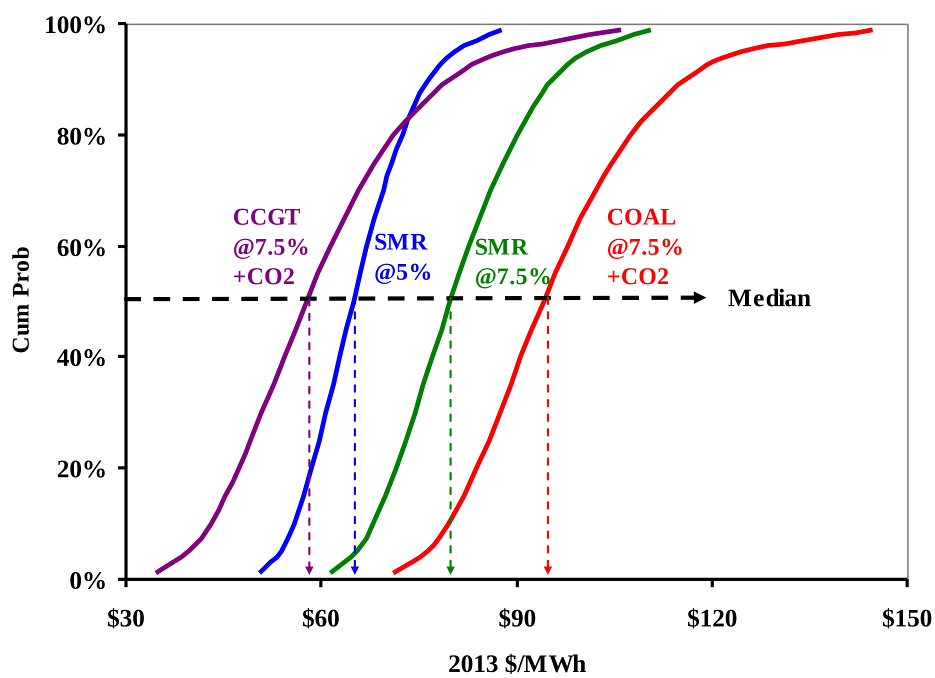
Coal with Scrubbers		**(1)**	**(2)**	**(3)**	**(4)**	**MIT**	**MIT**
Levelized Cost		**COAL**	**COAL**	**COAL**	**COAL**	**COAL**	**COAL**
All values in 2013 dollars	**r =**	**3.0%**	**5.0%**	**7.5%**	**10.0%**	**7.8%**	**7.8%**
Net Electrical Capacity	MWe	1,300	1,300	1,300	1,300	1,000	1,000
Average Capacity Factor	%	***67%***	***67%***	***67%***	***67%***	**85%**	**85%**
Plant depreciation life	Years	40	40	40	40	40	40
Construction Lead Time	Years	4	4	4	4	4	4
Base Overnight Cost	$/kw	$2,775	$2,775	$2,775	$2,775	$2,078	$2,078
Contingency (from EIA)	%	7%	7%	7%	7%	7%	7%
Total Overnight Cost	$/kw	$2,969	$2,969	$2,969	$2,969	$2,223	$2,223
Interest During Construction factor	%	6.0%	10.2%	15.5%	21.0%	16.2%	16.2%
KC per kW with IDC	$/kw	$3,148	$3,271	$3,430	$3,593	$2,583	$2,583
KC, Total Capital Investment Cost	$ M	$4,092	$4,252	$4,459	$4,671	$2,583	$2,583
Fuel Price ($/GJ = 0.948 x $/Mbtu)	$/Mbtu	***$2.18***	***$2.18***	***$2.18***	***$2.18***	**$2.18**	**$1.46**
CO2 Price ($/tonne)	$/tonne	**$25.00**	**$25.00**	**$25.00**	**$25.00**	**$25.00**	**$25.00**
CO2 per MWh ("carbon intensity factor")	t/MWh	0.827	0.827	0.827	0.827	0.839	0.839
Heat Rate (from EIA, 2013)	BTU/kWh	8,740	8,740	8,740	8,740	8,870	8,870
Variable O&M	$/MWh	$4.52	$4.52	$4.52	$4.52	$4.07	$4.07
Fixed O&M + Incremental Capital Costs	$/kW	$31.56	$31.56	$31.56	$31.56	$58.09	$58.09
Levelized Capital Cost	$/MWh	$23.28	$32.59	$46.56	$62.82	$28.45	$28.45
Levelized O&M Cost	$/MWh	$9.92	$9.92	$9.92	$9.92	$11.86	$11.86
Levelized Fuel Cost	$/MWh	$19.07	$19.07	$19.07	$19.07	$19.35	$12.99
Levelized Fuel CO2 Cost	$/MWh	$20.67	$20.67	$20.67	$20.67	$20.98	$20.98
Levelized Cost without CO2 cost	**$/MWh**	**$52.26**	**$61.57**	**$75.54**	**$91.80**	**$59.66**	**$53.30**
Levelized Cost with CO2 cost	**$/MWh**	**$72.93**	**$82.24**	**$96.21**	**$112.47**	**$80.64**	**$74.27**

Figure 3.2.3: Coal Levelized Cost, Simulated Cumulative Distributions (r = 5%, 7.5%)



Sources: Figures 3.1.1, 3.1.2, 3.2.2, and Table 3.2.2

Figure 3.2.4: SMR, Natural Gas, and Coal Levelized Costs, Simulated Cumulative Distributions without and with a CO_2 Fee

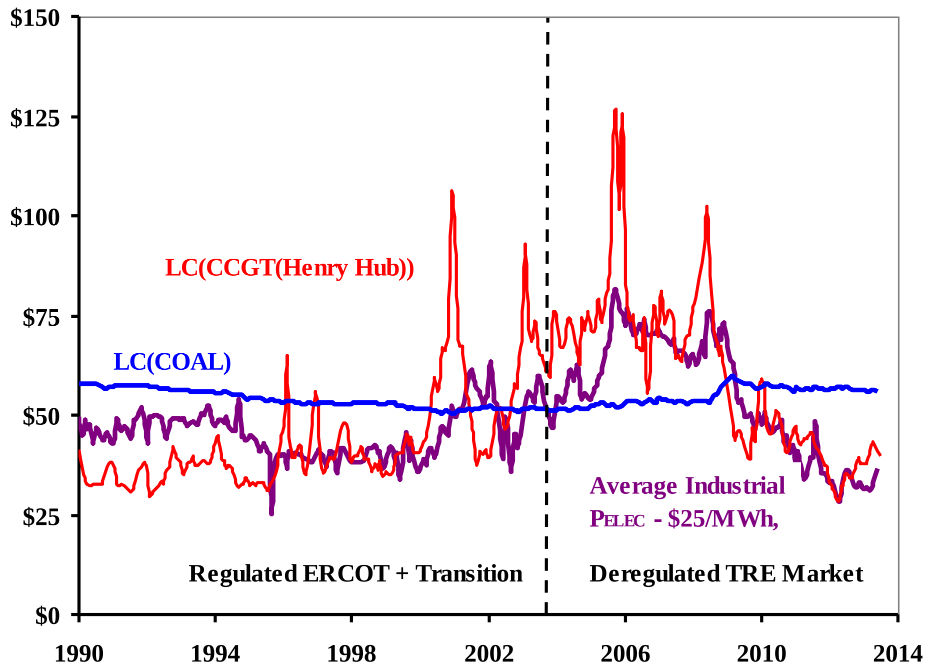


Sources: Figures 2.8.2, 3.1.5, and 3.2.3

Section 4: A Probabilistic Analysis of Portfolios of Electricity Generating Assets

While the simulations in Figure 3.2.4 are interesting, without an explicit understanding of who is choosing among these technologies and how these decision makers value the trade-off between levelized cost and the standard deviation of levelized cost, there is no obvious choice, because no technology stochastically dominates the others (when the cost of carbon dioxide is taken into account). In earlier times (and still in some states of the U.S.), the choice of which technology to build was determined through the interaction of the electric utility regulator (representing the rate payers) and the power plant owner-operators, who enjoyed a monopoly in electricity provision in their regulated territory. More recently, in half the U.S., an electricity market is guiding the choice of electricity generation technology.

Figure 4.1.1: Electricity Prices in Texas ERCOT/TRE, 1990-2013



Source: http://www.eia.gov/electricity/data.cfm#sales

Figure 4.1.1 presents the average industrial price of electricity in Texas between 1991 and 2013 with a mean of \$74.17/MWh and a standard deviation of \$11.83/MWh. (This mean is used below to evaluate the competitive feasibility of portfolios of generating assets.) After electricity market deregulation in Texas, electricity prices closely followed the levelized costs of generating electricity with natural gas. The four natural gas price spikes (in Figure 3.1.3) led to two electricity price spikes near spike III (September-December 2005) and spike IV (June 2008), both were offset by lower coal prices. The contagion of price volatility can be seen in Figure 4.1.1, where the red line transforms Henry Hub natural gas into electricity at levelized cost, **LC(CCGT)**, the blue line is the levelized cost of coal, **LC(COAL)**, and the purple line is the average price of electricity in Texas, $\mathbf{P_{ELEC}}$ (minus \$25 to minimize the distance between the red and purple lines to show how the two series move together).

Since the mid-1990s, some areas have deregulated and hence the default decision maker is the power plant investor competing in a wholesale electricity market. Under regulation, a portfolio of generating assets emerged over generations of rate payers. (See Jansen, Beurskens, and Tilburg, 2006, for a theoretical treatment of this topic.) Under liberalized markets merchant generators select technologies that maximize profits, and rate payers accept the risk of volatile electricity prices. With electricity market liberalization and a general decline in the price of natural gas, there has been a "dash to gas," because natural gas has generally been the marginal producer, and hence, the price setter. By dashing to natural gas, investors minimize their revenue risk. But this dash has increased natural gas demand and has created bottlenecks where natural gas pipelines constrain the flow of natural gas into some regions of the U.S., such as California.

What is absent is the basic tenant of modern finance theory: diversification reduces risk for each level of return. Here, a diversification of generating assets could reduce levelized cost risk at each value of levelized cost. However, transferring the accepted wisdom from financial markets to electricity markets is not straightforward. In financial markets, stocks, bonds, and derivatives can be purchased in small chunks and mixed to form an optimal portfolio for each investor. Real estate can be included through investments in Real Estate Investment Trusts and gold can be included through investments in gold mining corporations. Hence, an optimal portfolio need not contain anything "real," as in real property.

On the other hand, electricity generating assets are real and bulky. For example, the standard size of a combined-cycle natural gas turbine *unit* is about 400 MW, the standard size of a coal power *unit* with modern air pollution equipment is about 600 MW, an advanced light water nuclear power *unit* is about 1,200 MW, and small modular light water reactors, now under development, are 45 to 180 MW per *unit*, or about 400 MW per *plant*.

Also, because of regulatory restrictions by the Securities and Exchange Commission, the Federal Energy Regulatory Commission, the Environmental Protection Agency, the Nuclear Regulatory Commission, state and local water commissions, local property owners with stakes to drive into any electricity generation project, owner-operators find it difficult to manage these bulky assets to produce both (1) outputs and (2) revenues to pay bankers and investors. Also, because of the necessity of providing "uninterruptable" electric power, the generating portfolio must meet all demand (load) at all times, e.g., during heat waves and polar vortexes.

A rule of thumb is that no single generating asset should be larger than 10% of the connected transmission grid; therefore, one needs either (1) a minimum system size composed of natural gas-fired units and/or SMRs of 4,000 MW (if no single unit is greater than 400 MW or 10% of the grid size); or (2) a minimum system size composed of natural gas-fired or coal-fired units and/or SMRs of 6,000 MW (if no single unit is greater than 600 MW). Of course, smaller systems could be built at higher delivered power prices; at the limit, "distributed" systems can be built of any size, provided that backup power is available. However, because of the integer divisibility of the 6,000 MW systems with 400 MW plants, a system of 6,000 MW is considered here to be the minimum standard system (maximum dependable electricity generating capacity) for adding SMRs.

Section 4.1: A Portfolio of Fossil-Fired Electricity Generating Assets

Given that generating assets are discrete and that the portfolio's levelized cost and variance will be equal to a weighted sum of the underlying assets' levelized costs, variances, and correlations (see Equation A2.6 and Equation A2.7 in the Appendix). Table 4.1.1 presents the results of simulating portfolios of 6,000 MW. These results are plotted in Figure 4.1.2. The minimum standard deviation is achieved with a portfolio of one-half coal-fired units (here, 10 units) and one-half natural gas-fired units (here, 15 units). (Compare with Table A2.4.) Because of the low correlation between natural gas and coal prices, combining coal-fired units with natural gas-fired units lowers the variance of the levelized cost of electricity. (Natural gas and coal prices are positively correlated at 35% for data in Figure 3.1.4 and Figure 3.2.2; natural gas and uranium prices are barely correlated at 4%; and coal and uranium prices are negatively correlated at −20%.) In the simulations of LC, LC_{CCGT} and LC_{COAL} are correlated at positive 30%, but LC_{SMR} is uncorrelated with either LC_{CCGT} or LC_{COAL}.) Some portfolios (in red in Table 4.1.1) yield levelized costs above $74/MWh and are, therefore, inadvisable. (Although the price of electricity is itself a randomly distributed variable, particularly across states in the U.S., the average electricity price should not be considered a "red line," but more like a "guideline.")

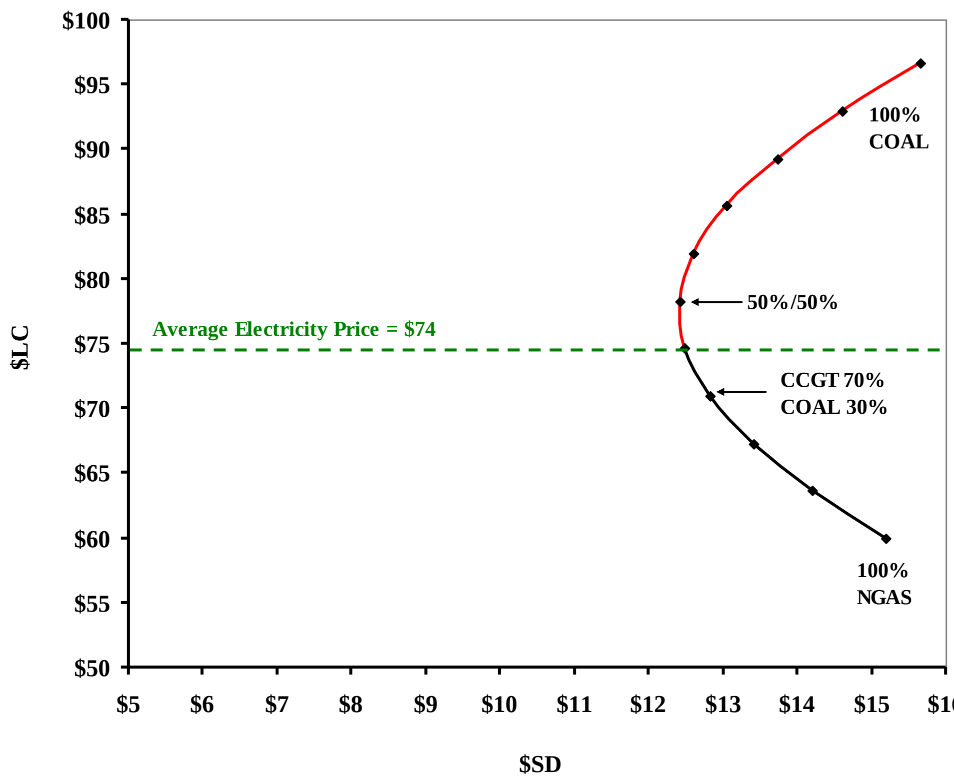
Also, Table 4.1.1 presents sums of levelized cost, LC, plus various multiples of the simulated standard deviation, SD, where the multipliers are from Table A1.1. Holding the risk aversion parameter to 1, the multipliers increase with the requirement of higher levels of confidence (80% to 99%) in the cost estimate and with larger accuracy ranges (i.e., with less well developed cost estimates).

Values in bold are the minimum values in each row. For example, the lowest levelized cost, LC, is $60 with an all-CCGT system, but the system that yields the lowest standard deviation, SD, is one with half CCGT and half coal. The lowest LC plus one SD through three SD points to all-CCGT systems. However, as multiples increase, the no-regrets strategy appears to be 70% CCGT with 30% COAL with a SD that is 19% lower than the all-CCGT system, i.e., one-third coal capacity stabilizes the levelized cost volatility associated with natural gas prices.

Table 4.1.1: Portfolios of Natural Gas and Coal-Fired Units

TOTAL	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
CCGT	6,000	5,400	4,800	4,200	3,600	3,000	2,400	1,800	1,200	600	0
COAL	0	600	1,200	1,800	2,400	3,000	3,600	4,200	4,800	5,400	6,000
LC	**$60.0**	$63.6	$67.3	$71.0	$74.6	$78.3	$82.0	$85.6	$89.3	$92.9	$96.0
SD	$15.2	$14.2	$13.4	$12.8	$12.5	**$12.4**	$12.6	$13.1	$13.7	$14.6	$15.7
LC+SD	**$75**	$78	$81	$84	$87	$91	$95	$99	$103	$108	$112
LC+2SD	**$90**	$92	$94	$97	$100	$103	$107	$112	$117	$122	$127
LC+3SD	**$105.6**	$106.3	$108	$109	$112	$116	$120	$125	$130	$137	$143
LC+4SD	$121	**$120**	$121	$122	$125	$128	$132	$138	$144	$151	$159
LC+5SD	$136	$135	**$134**	$135	$137	$140	$145	$151	$158	$166	$174
LC+6SD	$151	$149	**$147.8**	$148	$150	$153	$158	$164	$172	$181	$190
LC+7SD	$166	$163	$161	**$161**	$162	$165	$170	$177	$185	$195	$206

Figure 4.1.2: Portfolios of Natural Gas and Coal-Fired Generating Assets



Source: Table 4.1.1

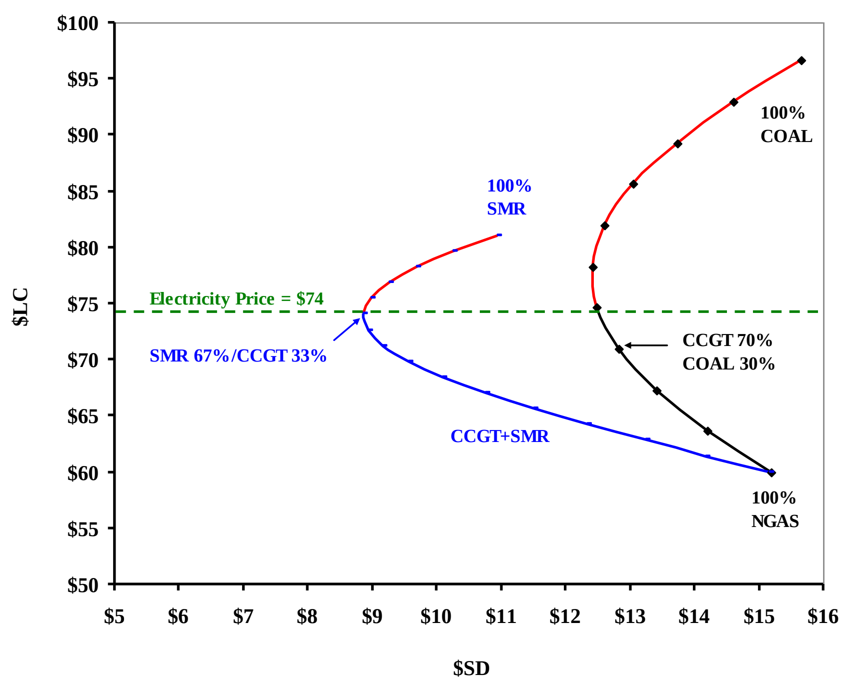
Section 4.2: Adding SMRs to a Portfolio of Fossil-Fired Electricity Generating Assets

Table 4.2.1 adds SMR plants of 400 MW to a portfolio of all CCGTs. The standard deviation of the portfolio continues to decrease with the addition of SMRs, as shown in Figure 4.2.1. Some portfolios (in red in Table 4.2.1) yield levelized costs above $74/MWh and are, therefore, inadvisable, i.e., an all-SMR system appears to be too expensive at this time. On the other hand, a portfolio of one-third CCGTs and two-thirds SMRs appears to have the lowest standard deviation of levelized cost. Because of the lack of correlation between SMRs and fossil-fired units, adding SMRs decreases the cost riskiness of the portfolio.

Table 4.2.1: Portfolios of CCGTs and SMRs (not all columns presented)

TOTAL	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
CCGT	6,000	5,200	4,400	3,600	3,200	2,800	2,400	2,000	1,600	800	0
SMR	0	800	1,600	2,400	2,800	3,200	3,600	4,000	4,400	5,200	6,000
LC	**$60.0**	$62.8	$65.6	$68.4	$69.8	$71.2	$72.6	$74.0	$75.4	$78.2	$81.0
SD	$15.2	$13.2	$11.5	$10.1	$9.6	$9.2	$8.94	**$8.87**	$9.0	$9.7	$10.9
LC+SD	**$75.2**	$76.0	$77.1	$78.5	$79.4	$80.4	$81.6	$82.9	$84.4	$87.9	$92.0
LC+2SD	$90.3	$89.3	$88.64	**$88.61**	$88.9	$89.6	$90.5	$91.8	$93.4	$97.6	$102.9
LC+3SD	$106	$103	$100	$99	**$98**	$99	$99	$101	$102	$107	$114
LC+4SD	$121	$116	$112	$109	$108.1	**$107.9**	$108	$110	$111	$117	$125
LC+5SD	$136	$129	$123	$119	$118	$117	**$117**	$118	$120	$127	$136
LC+6SD	$151	$142	$135	$129	$127	$126	**$126**	$127	$129	$136	$147
LC+7SD	$166	$155	$146	$139	$137	$135	**$135**	$136	$138	$146	$158

Figure 4.2.1: Portfolios of SMR and Natural Gas Generating Assets



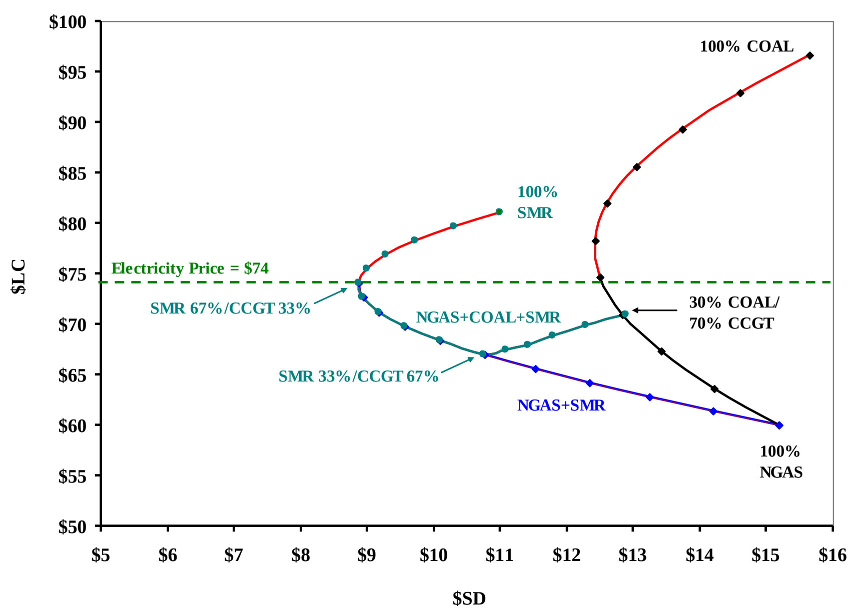
Source: Table 4.2.1

Table 4.2.2 adds SMRs to a portfolio of 70% CCGTs and 30% coal capacity: first replacing coal capacity, then replacing CCGTs. There is a dramatic reduction in *both* the levelized cost and the standard deviation of levelized cost with the replacement of coal units with SMRs. Once coal is replaced, SMRs can still reduce cost risk by replacing CCGTs, following the same path to the same point of two-thirds SMRs and one-third CCGTs as in Figure 4.2.1.

Table 4.2.2: Portfolios of Fossil-Fired Units and SMRs (not all columns presented)

TOTAL	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
CCGT	4,200	4,200	4,200	4,000	3,200	2,800	2,400	2,000	1,600	0
COAL	1,800	1,000	200	0	0	0	0	0	0	0
SMR	0	800	1,600	2,000	2,800	3,200	3,600	4,000	4,400	6,000
LC	$70.97	$68.89	**$66.82**	$67.00	$69.81	$71.21	$72.62	$74.02	$75.43	$81.04
SD	$12.89	$11.79	$11.19	$10.75	$9.56	$9.17	$8.93	**$8.88**	$8.99	$11.00
LC+SD	$84	$81	$78	**$77.8**	$79	$80	$82	$83	$84	$92
LC+2SD	$97	$92	$89	**$88.5**	$89	$90	$90	$92	$93	$103
LC+3SD	$110	$104	$100	$99	**$98.5**	$99	$99	$101	$102	$114
LC+4SD	$123	$116	$112	$110	$108	**$107.9**	$108	$110	$111	$125
LC+5SD	$135	$128	$123	$121	$118	**$117.0**	$117	$118	$120	$136
LC+6SD	$148	$140	$134	$132	$127	**$126.2**	**$126.2**	$127	$129	$147
LC+7SD	$161	$151	$145	$142	$137	$135	**$135.1**	$136	$138	$158

Figure 4.2.2: Portfolios of Natural Gas, Coal-Fired, and SMR Generating Assets



Source: Table 4.2.2

This analysis would suggest that the cost-risk-minimizing path for minimizing CO_2 emissions while maintaining competitive electricity prices in a medium-sized electricity system (6,000 MW) would be to first replace coal units (that have not already been replaced with natural gas units) with nuclear units. Then continue to replace natural gas units with nuclear power units until an trade-off is achieved between the long-run stability of nuclear power costs and the short-run cheapness of natural gas, i.e., replace CCGTs with nuclear units as the price of natural gas rises to international equilibrium prices.

Section 5: Summary and Conclusions

This paper has extended the "Levelized Cost of Electricity" literature by showing that there is no "best" levelized cost, but a probability distribution of levelized costs as a function of underlying randomly-distributed cost drivers and assumed parameters. It has modelled these probability distributions for Small Modular (Light Water) Reactors, combined-cycle natural gas turbines, and coal-fired steam-electric units with advanced pollution control equipment.

To limit the complexity of the analysis, this paper restricted the class of probability densities to those in the "normal" family and to those that have closed-form distribution functions. After empirically estimating these probability densities, it simulated levelized costs in portfolios of base-load generating assets.

In a portfolio of fossil-fired assets, this paper found that the diversity in the combination of two-thirds natural gas and one-third coal assets minimized the standard deviation of levelized cost while remaining competitive. This result is a function of two facts: (1) the levelized cost of electricity for natural gas (with or without carbon prices) is less than the cost of coal, and (2) the price of natural gas is not highly correlated with the price of coal, hence coal helps stabilize the levelized cost of electricity during price spikes in the cost of natural gas and bottlenecks in natural gas transmission. Further, because there is little cost covariance between fossil-fired generators and SMRs, adding SMRs reduces the standard deviation of the fossil portfolio, and as risk aversion increases, the role of SMRs in generation portfolios becomes more valuable. To reduce the unknowns associated with carbon emissions and to reduce the volatility of electricity prices, electric utilities, and their investors and financiers, should consider adding new nuclear power to their unnaturally gas-heavy (CH_4 and CO_2) generating assets.

Finally, the analysis showed that the cost-risk reducing path for minimizing electricity cost risk and CO_2 emissions while maintaining competitive electricity prices in a medium-sized electricity system would be to first replace coal units with nuclear units, then replace natural gas units as the price of natural gas rises.

Therefore, encouraging nuclear power plant construction in the U.S. to achieve clean emissions standards should focus on reducing the cost of capital and the risks of building new nuclear. Reducing the cost of construction is the responsibility of the builder ("on time and on budget"), the owner (by diversifying generation assets), the operator (with high safety and reliability), the federal government (by creating programs similar to those in the *Energy Policy Act of 2005* to overcome capital market failures), and Wall Street (through becoming familiar with new nuclear technology). With these forces aligned, in the next two decades, the U.S. could build an SMR manufacturing industry on a foundation of the world's most successful Nuclear Navy, replace retiring fossil-fired and nuclear plants with small passively-safe reactors, and provide a basis for rapidly reducing U.S. greenhouse gas emissions.

Appendix A: Risk, Uncertainty, and Diversification in Portfolios

This appendix explores the quantification of risk premiums in the evaluation of uncertainty in cost drivers associated calculating the levelized cost of electricity. Section A1 presents the microeconomics of risk aversion and the relationship between cost uncertainty and cost contingency, as discussed in Section 2.2. Section A2 shows how to calculate the mean and variance (or standard deviation) of a portfolio of financial equities, as discussed in Section 4.

Section A.1: Risk Aversion, Risk Premiums, and Cost Contingency

The standard deviation of the cost estimate, σ, is a measure of cost estimate uncertainty. For a cost estimate with a normal distribution, about 68% of the probability is between plus and minus one standard deviation ($\pm\ \sigma$) of the mean. Determining the proper contingency for the expected cost estimate is a function of this uncertainty and the decision maker's aversion to uncertainty. But the cost engineering literature neglects the decision maker's risk aversion.

The economic theory of risk aversion is well developed and can be applied to the problem of calculating levelized cost contingency. The theory focuses on how to determine how much compensation (or risk premium) a decision maker requires before accepting a risky proposition. To describe how investors evaluate risk, economics analyzes how decision makers choose between uncertain alternatives. Microeconomic theory assumes that consumers (or investors) purchase goods and services (or financial instruments) to maximize their "utility" or "welfare." See Copeland, Weston, and Shastri (2005) for a more extensive discussion.

The question addressed by economists is how decision makers (individuals, firms, governments, and societies) rank different levels of wealth that might result from choosing among risky alternatives. These choices are modeled by assuming a "welfare" function: $W(\Omega)$, where Ω represents the decision maker's net present wealth. The welfare function must be such that if $\Omega_1 > \Omega_2$, then $W(\Omega_1) > W(\Omega_2)$. But if Ω_1 and Ω_2 were both uncertain, as they would be if wealth involved financial instruments (or electricity generating assets), then how would decision makers compare uncertain outcomes? First, the expected value of wealth is the sum of all the possible values of wealth times the probability of each value. This is expressed as the mean (the probability-weighted average) of wealth. While the estimate of this mean has a standard error, it has a certain, specific value. Thus, while Ω is uncertain, its expected value, $E(\Omega)$, is considered certain. Second, the attitude toward uncertainty can be described in terms of the relationship between (1) the *welfare of the expected value of the certain outcome,* $W[E(\Omega)]$, and (2) the *expected welfare of the uncertain outcome,* $E[W(\Omega)]$.

To describe risk averse behavior, consider the following definitions:

if $W[E(\Omega)] > E[W(\Omega)]$, then decision makers are *"Risk Averse*," i.e., they have higher levels of welfare with more certainty;

if $W[E(\Omega)] = E[W(\Omega)]$, then decision makers are *"Risk Neutral*," i.e., they are indifferent toward uncertainty; or

if $W[E(\Omega)] < E[W(\Omega)]$, then decision makers are *"Risk Preferring*," i.e., they have lower levels of welfare with more certainty.

The "risk premium," Φ, equates the two sides of the definition of risk aversion: $W[E(\Omega)] = (1 + \Phi) \cdot E[W(\Omega)]$. The risk premium is a function of at least two variables: (1) the degree of risk aversion, RA, e.g., how much does welfare increase with certainty, and (2) risk, where risk is defined as "known" uncertainty, e.g., there is enough information to specify its probability distribution, even though a specific value is unknown. Hence, risk is measured as the standard deviation, $\boldsymbol{\sigma}$, of the risky outcome, where $\boldsymbol{\sigma}^2$ is the variance of the risky outcome.

A cost estimation contingency, $\mathbf{C_{ON}}$ (contingency percentage rate) based on this approach to calculating risk premiums (i.e., the value of the contingency multiplier) can be formulated as

$$\mathbf{C_{ON}} \quad = \quad \Phi(\text{RA}, \boldsymbol{\sigma}), \qquad \text{(A1.1)}$$

where $\Phi(\text{RA}, \sigma)$ is a function of the level of risk aversion, RA, and the standard deviation, $\boldsymbol{\sigma}$; Pratt (1964). This function calculates the appropriate contingencies to levelized cost, yielding a "certainty-equivalent" levelized cost, i.e., one that would equate for the risk taker (e.g., a public utility) an *uncertain* levelized cost with a *certain* one. This definition of contingency assumes that decision makers ignore higher order moments, such as skewness (whether the distribution is symmetric) and kurtosis (whether it has fat tails, increasing the probability of "black swan" events, Taleb, 2010, p. 355).

To calculate contingency, Equation (A1.1) must be specified by empirical observation or experimentation, because economic theory does not explicitly state the form of the $\Phi(\text{RA}, \boldsymbol{\sigma})$ function. First, what is an appropriate value of RA? Second, what is the appropriate estimate of the standard deviation, $\boldsymbol{\sigma}$, of a cost estimate?

First, to determine a reasonable value for RA, consider the implicit assumptions regarding risk aversion in standard cost-engineering guidelines. In these guidelines, contingencies are suggested *without regard to the size of the project or the size of the firm*. Hence, the guidelines implicitly assume Constant Risk Aversion. Under Constant Risk Aversion, cost-engineering estimating practices implicitly suggest that RA = **c**, a constant across all decision-maker types. If $\Phi(\text{RA}, \sigma) = \mathbf{c} \cdot \sigma$ (i.e., that the decision maker's evaluation of the standard deviation is well approximated by a first-order Taylor series expansion) contingency, then $\mathbf{C_{ON}}$ becomes

$$\mathbf{C_{ON}} \quad = \quad \mathbf{c} \cdot \sigma, \qquad \text{(A1.7)}$$

i.e., the appropriate level of contingency is equal to a constant, **c**, times the standard deviation of a risky project's cost. While economic theory does not provide a specific value for **c**, there could be an implicit value of **c** in cost engineering guidelines. However, under prospect theory (Kahneman, 2011, p. 278-286), decision makers react differently to losses than to gains, so $\Phi(\text{RA}, \sigma)$ could not be equal to $\mathbf{c} \cdot \sigma$.

Under a normal distribution, (1) for a "Finalized Estimate" with an accuracy **range** = ±10% and an 80% confidence, σ = 7.8%

with **c** = 0.64, $\mathbf{C_{ON}}$ = 0.64 · 7.8% = 5%;

with **c** = 1.00, $\mathbf{C_{ON}}$ = 1.00 · 7.8% = 7.8%; and with $\mathbf{c} = 1.28$, $\mathbf{C_{ON}} = 1.28 \cdot 7.8\% = 10\%$;

implying a band of contingency rates from 5% to 10%; (2) for a "Detailed Estimate" with **range** = ±20% and an 80% confidence, σ = 15.6% with a band from 10% to 20%; and (3) for a "Preliminary Estimate" with **range** = ±30% and an 80% confidence, σ = 23.4% with a band from 15% to 30%. So if **c** is a constant, **c** could be in the range of 0.64 to 1.28, which satisfies both AACEI and EPRI guidelines on contingency. A value of 0.64 implies more tolerance to risk and a value of 1.28 implies less tolerance of risk. But these values imply an accuracy **range** of ±10% with an 80% confidence. How does this value change with changes in the accuracy range and the level of confidence?

Assuming a normal distribution with 80% of the distribution between ±10% (for generalization to non-normal distributions, see Rothwell, 2011, pp. 95-97):

$$\mathbf{C_{ON}}|_{80\%,} \approx \boldsymbol{\sigma}\,(1.28/1.28) = \boldsymbol{\sigma}\,(1.00),\ \text{e.g., } 7.8\% \qquad \text{(A1.2)}$$

Following this logic, for higher levels of confidence, e.g., 90%, 95%, 97.5%, 99%, or 99.5% and an accuracy of ±10% the contingency would increase as follows:

$$\mathbf{C_{ON}}|_{90\%} \approx \boldsymbol{\sigma}\,(1.645/1.28) = \boldsymbol{\sigma}\,(1.29),\ \text{e.g., } 7.8\%\,(1.29) = 10\% \qquad \text{(A1.3)}$$

$$\mathbf{C_{ON}}|_{95\%} \approx \boldsymbol{\sigma}\,(1.960/1.28) = \boldsymbol{\sigma}\,(1.53),\ \text{e.g., } 7.8\%\,(1.53) = 12\% \qquad \text{(A1.4)}$$

$$\mathbf{C_{ON}}|_{97.5\%} \approx \boldsymbol{\sigma}\,(2.224/1.28) = \boldsymbol{\sigma}\,(1.74),\ \text{e.g., } 7.8\%\,(1.74) = 14\% \qquad \text{(A1.5)}$$

$$\mathbf{C_{ON}}|_{99\%} \approx \boldsymbol{\sigma}\,(2.576/1.28) = \boldsymbol{\sigma}\,(2.01),\ \text{e.g., } 7.8\%\,(2.01) = 16\% \qquad \text{(A1.6)}$$

$$\mathbf{C_{ON}}|_{99.5\%} \approx \boldsymbol{\sigma}\,(2.810/1.28) = \boldsymbol{\sigma}\,(2.20),\ \text{e.g., } 7.8\%\,(2.20) = 17\% \qquad \text{(A1.7)}$$

The multipliers [1.0, 1.29, 1.53, 1.74, 2.01, 2.20] can be generalized to various accuracy ranges:

Table A1.1: Risk Multipliers to Apply to the Standard Deviation of a Cost Estimate

σ/7.8% x	**Accuracy Range**		
Confidence	**±10%**	**±20%**	**±30%**
80.0%	1.0	2.0	3.0
90.0%	1.3	2.6	3.9
95.0%	1.5	3.1	4.6
97.5%	1.7	3.5	5.2
99.0%	2.0	4.0	6.0
99.5%	2.2	4.4	6.6

Because it is not possible to simultaneously determine the risk aversion constant, confidence in the cost estimate, and the range of accuracy, under the assumption of Constant Risk Aversion (where the constant, **c**, is set equal to 1), the cost contingency can be approximated as some multiple of the standard deviation of the (levelized) cost estimate, which can be estimated either (1) by expert judgment, or (2) by using statistical or Monte-Carlo techniques, as in this paper; see Section 4.

Section A.2: Risk and Diversification

In well-defined capital markets, the price of risk can be calculated by determining the probability distributions of historic rates of return. This section explores how risk can be reduced by investing in a *portfolio* of assets following modern finance theory. For more on this example, see Rothwell and Gomez (2003).

To maximize expected return for a specific level of risk, individuals invest in a diverse set of financial instruments. (This might be different for how societies invest in public assets, just as the social discount rate differs from an individual's or a firm's discount rate.) As an example, consider the portfolio of common corporate stocks selected by Dow Jones & Company. Dow Jones tracks three portfolios of common stocks: Industrials, Transportation, and Utilities. The Dow Jones Industrial Average is a portfolio of 30 common stocks of large industrial corporations headquartered in the U.S.

Table A2.1 lists the *monthly* percentage returns (from a randomly selected year) for 3 companies listed in Table A2.2, which lists the company name and the common stock symbol. The *nominal return* is

$$R_t \quad = \quad (P_{t+1} - P_t) / P_t , \qquad \text{(A2.1)}$$

where P_t is the period-t price of the stock. Also included in Table A2.1 is the (value-weighted, i.e., weighted by the total value of each firm's stock) average return for the New York Stock Exchange, NYSE.

Investors compare average returns and risk (generally defined as the standard deviation of the returns) for each stock. The average, or *expected value* of the return, $E(R_t)$, is defined as

$$E(R_t) \quad = \quad (1/T) \cdot \Sigma R_t \quad \text{for } t = 1, \ldots, T. \qquad \text{(A2.2)}$$

The most common measure of variation is the *standard deviation*, $SDev(R_t)$, which is the square root of the *variance*, $Var(R_t)$:

$$Var(R_t) \quad = \quad [1/(T-1)] \cdot \Sigma [R_t - E(R_t)]^2 \text{ for } t = 1, \ldots, T. \qquad \text{(A2.3)}$$

Table A2.2 lists percentage values of $E(R_t)$, $SDev(R_t)$, and $Var(R_t)$ for the 3 stocks in Table A2.1. An unbiased estimator for sample variance accounts for the degree of freedom lost in calculating the sample mean, i.e., using $[1/(T-1)]$ in place of $(1/T)$ in Equation (A2.3). Table A2.3 lists the correlations between these stocks and the stock market as a whole.

Notice in Table A2.2 that the standard deviation of the returns to the market (NYSE) is lower than or equal to the standard deviations of the individual stocks. This is because the variance of a portfolio depends on (1) the variances of the stocks in the portfolio, and (2) the covariances between these stocks. *Covariance* between the returns on two stocks, j and k, is

$$Cov(R_{jt}, R_{kt}) \quad = \quad [1/(T-1)] \cdot \Sigma [R_{jt} - E(R_{jt})] [R_{kt} - E(R_{kt})] \qquad \text{(A2.4)}$$

for $t = 1, \ldots, T$. Although portfolio variance is a function of covariance between the stocks in the portfolio, it is easier to work with *correlation*, defined as

$$Corr(R_{jt}, R_{kt}) \quad = \quad Cov(R_{jt}, R_{kt}) / [SDev(R_{jt}) \cdot SDev(R_{kt})] . \qquad \text{(A2.5)}$$

Positive correlation implies that the two stocks move up and down together. Negative correlation implies that the two stocks move in opposite directions. If the correlation coefficient is 1, the two stocks move in the same direction (i.e., are perfectly positively correlated). If the correlation coefficient is 0, then the two stocks move independently. If the correlation coefficient is –1, the two stocks are perfectly negatively correlated.

Table A2.1: Monthly Returns for 3 Stocks in the Dow Jones Industrial Average

	NYSE	AXP	BA	CHV
Jan.	**5.30%**	10.00%	0.60%	2.10%
Feb.	**-0.10%**	5.60%	-4.80%	-2.00%
March	**-4.40%**	-8.80%	-3.10%	7.90%
April	**4.30%**	10.20%	0.00%	-1.60%
May	**7.10%**	5.70%	7.10%	3.00%
June	**4.40%**	7.20%	0.70%	5.60%
July	**7.60%**	12.70%	10.60%	6.80%
Aug.	**-3.70%**	-7.20%	-6.90%	-1.20%
Sept.	**5.80%**	5.30%	-0.10%	7.30%
Oct.	**-3.40%**	-4.50%	-11.80%	-0.20%
Nov.	**3.10%**	1.10%	11.00%	-2.60%
Dec.	**1.80%**	13.40%	-7.90%	-4.00%

Table A2.2: Annual Returns to 3 Stocks in the Dow Jones Industrial Average

Symbol	Corporation	E(R)	SD(R)
NYSE	New York Stock Exchange	2.32%	4.28%
AXP	American Express	4.24%	7.53%
BA	Boeing	-0.38%	7.16%
CHV	Chevron	1.77%	4.28%

Table A2.3: Correlations between 3 Stocks in the Dow Jones Industrial Average

CORRs	NYSE	AXP	BA	CHV
NYSE	100%			
AXP	81%	100%		
BA	73%	36%	100%	
CHV	25%	**-8%**	31%	100%

For example, the correlation between the returns on American Express and Chevron is –8%: American Express, a financial services provider, and Chevron, a petro-chemical company, although negatively related, are almost independent. To take advantage of this (slightly negative) independence, a portfolio of assets can be constructed in the following way. (A portfolio of electric generating plants can be done in the same way, as in Section 4.) The *expected return of a portfolio* of 2 stocks is

$$\text{E(Portfolio Return)} \quad = \quad x \cdot \text{E}(R_{jt}) + (1 - x) \cdot \text{E}(R_{kt}) \ , \tag{A2.6}$$

where x is the proportion of value of the portfolio invested in one stock and $(1 - x)$ is the proportion of value of the portfolio invested in the other stock. The *variance of a portfolio* of these two stocks is

$$\text{Var(Portfolio)} = x^2 \cdot \text{Var}(R_{jt}) + (1-x)^2 \cdot \text{Var}(R_{kt}) + 2 \cdot x \cdot (1-x) \cdot \text{Cov}(R_{jt}, R_{kt}) \tag{A2.7}$$

$$= x^2 \cdot \text{Var}(R_{jt}) + (1-x)^2 \cdot \text{Var}(R_{kt}) + 2 \cdot x \cdot (1-x) \cdot \text{Corr}(R_{jt}, R_{kt}) \cdot \text{SDev}(R_{jt}) \cdot \text{SDev}(R_{kt}).$$

For example, in an equally-weighted portfolio of American Express and Chevron,

(1) the expected return would be 3% = (0.5) · (4.24%) + (0.5) · (1.77%),

(2) the variance would be 0.179% =

$(0.5)^2 \cdot (7.53\%)^2 + (0.5)^2 \cdot (4.28\%)^2 + (2 \cdot 0.5 \cdot 0.5 \cdot -0.08 \cdot 7.53\% \cdot 4.28\%)$, and

(3) the standard deviation would be 4.14%,

which is less than the standard deviations of either of the two stocks because of the negative correlation between the two returns. By varying the proportions of stocks in the portfolio, the investor can find optimal combinations that minimize risk for each level of expected return. Of course, more than two stocks should be included in a portfolio. The Dow Jones Index relies on 30 stocks.

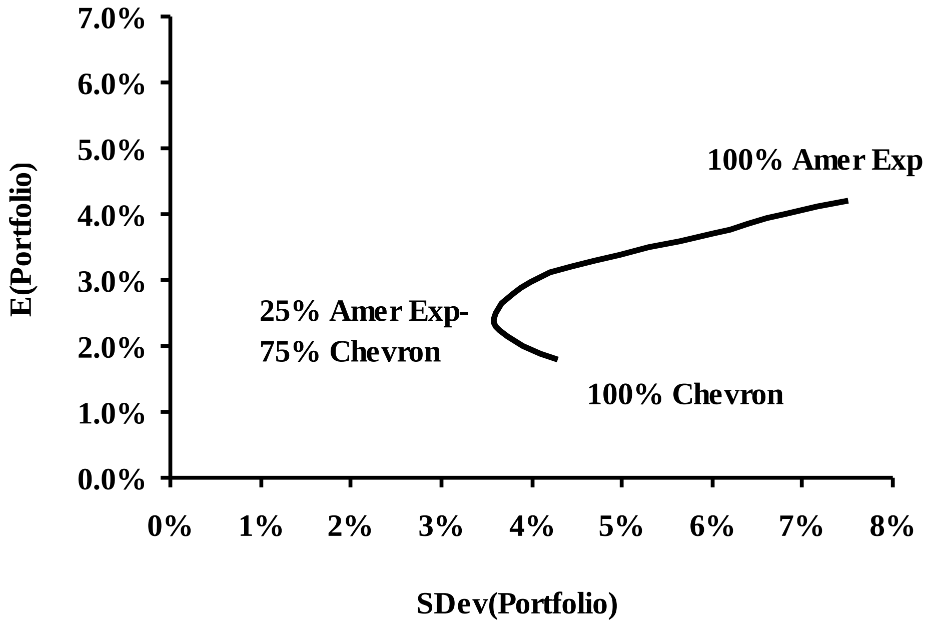
The expected return and standard deviation for a portfolio of American Express and Chevron can be calculated at $\boldsymbol{x}$ = 0%, 10%, … 90%, and 100% from the data in Table A2.2. Table A2.4 presents weighted averages of the returns and standard deviations of Chevron ($\boldsymbol{x}$ = 0%) and American Express ($\boldsymbol{x}$ = 100%). Figure A2.1 plots these values.

Table A2.4: Portfolio Returns and Standard Deviations with American Express and Chevron

x	**0%**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
E(Port)	1.8%	2.0%	2.3%	2.5%	2.8%	3.0%	3.3%	3.5%	3.7%	4.0%	4.2%
SDev(Port)	4.3%	3.9%	**3.6%**	**3.6%**	3.8%	4.2%	4.7%	5.3%	6.0%	6.8%	7.5%

Depending on the investor's indifference between risk and return, an optimal portfolio of these two stocks can be selected. For example, if the investor wanted to minimize risk, a portfolio of 20% to 30% of American Express would be most appropriate. On the other hand, if the investor wanted to simply maximize return without regard to risk, a portfolio of 100% American Express would be the most appropriate.

Figure A2.1: Portfolio Frontier for American Express and Chevron from Table A2.4



Source: Table A2.4

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Appendix B

Future Power Needs for DOE's Hanford Site and the Northwest Region

Contents

Figures

FUTURE POWER NEEDS FOR DOE'S HANFORD SITE AND THE NORTHWEST REGION

The ability to market power from a Hanford SMR will be largely dependent on the need for new sources of electrical power in the Northwest and the competiveness of SMR electrical power compared to other potential resources. Appendix B evaluates local and regional power needs including needs projected by federal agencies and utilities. It also addresses how those needs could be met with a Hanford SMR.

B.1 Regional Power Needs

B.1.1 Bonneville Power Administration Responsibilities

The Bonneville Power Administration was established by Congress in 1937 initially to market power from the Bonneville Dam. Since then, the BPA mission has been extended to marketing electrical power from the output of the Federal Columbia River Power System (FCRPS)[1] which consists of 31 federal hydro projects in the Columbia River Basin, one nonfederal nuclear plant and several other small nonfederal power plants. The dams are operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. The nuclear power plant is operated by Energy Northwest. The Northwest Power Act authorizes BPA to acquire resources to meet its contractual obligations. BPA does not own generating resources, so when BPA uses the term "acquire resources," it refers to contract purchases, not project ownership.

According to BPA (BPA 2012 White Book)[2], the annual average capacity of the federal resources (federally owned and under contract to BPA) is 8466 MW under 1937 water conditions. The 120-hour peak capacity of the system for the critical month of January is 12,958 MW. By contrast, the regional (Pacific Northwest) resources are 27,516 MW ave and 38,969 MW (120-hour January peak). The PNW region is represented by BPA's marketing area as defined by section 3(14) of the 1980 Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), P.L. 96-501, and includes Oregon, Washington, Idaho, Montana west of the Continental Divide, and portions of Nevada, Utah, and Wyoming that lie within the U.S. Columbia River drainage basin[3].

Under the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), any Northwest utility that is a qualified BPA customer can contract with BPA to supply its firm power needs to the extent that those needs are not met by its own resources. According to BPA's White Book, the federal resources are marketed to northwest utilities and other federal agencies through a tiered structure that was established during "BPA's 2008 Regional Dialogue (RD) Power Sales Contracts (PSCs) with Public Agency and Federal Agency customers. Under the PSCs BPA is obligated to provide power sold from October 1, 2011, through September 30, 2028. Three types of products were offered to customers: Load Following, Slice/Block, and Block. One hundred eighteen customers signed the Load Following service contract, 17 signed

[1] http://www.bpa.gov/news/AboutUs/Pages/Mission-Vision-Values.aspx

[2] http://www.bpa.gov/power/pgp/whitebook/2012/

[3] https://www.nwcouncil.org/media/5227150/poweract.pdf

the Slice/Block service contract, and no customers signed the Block only service contract. Under these power contracts, customers must make periodic elections pertaining to serving future load growth by customers either 1) adding new non-Federal resources, or 2) buying power from sources other than BPA, and/or 3) requesting BPA to supply power for load." Currently, the Tier 1 power costs slightly above $30/MW.

B.1.2 Regional Power Planning

Based on the impact they have on the Northwest power market, BPA conducts substantial planning activities to ensure an adequate supply of power is available for the Northwest. Every two years, BPA issues a White Book report titled the "Pacific Northwest Loads and Resources Study." The White Book estimates regional loads and resources for the following ten year period. Input for the White Book is provided by PNW Federal Agencies, public body, cooperative, and investor-owned utility customers through direct submittals to BPA and/or annual Pacific Northwest Utilities Conference Committee (PNUCC) data submittals. Each year, the White Book is followed by the "Resource Program"[4] report which uses data from the White Book and supplements it with economic analyses to assess resource acquisition for the future.

Plans for future capacity are also strongly influenced by planning performed by the Northwest Power and Conservation Council (Council)[5]. The Council was formed by the Northwest states in 1981 in accordance with the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Act) which was enacted to improve regional power planning, to ensure equitable allocation of federal resources marketed through BPA, and to provide for more public input into power planning. Passage of the Act followed a period of instability in power resources and the beginning of discussions leading to cancellation of 4 nuclear power plants under construction by Energy Northwest (which at that time was called the Washington Public Power Supply System). Each state's governor appoints two members to the Council making eight members in total representing Washington, Oregon, Idaho, and Montana. The Council was formed to give the Pacific Northwest states and the region's citizens a say in how growing electricity needs of the region would be provided. The Act charges the Council with creating and periodically updating a power plan for the region. The purpose of the Council's power plan is to ensure an adequate, efficient, economical, and reliable power supply for the Pacific Northwest.

The most recent plan prepared by the Council is the Sixth Northwest Conservation and Electric Power Plan Mid-Term Assessment Report dated March 13, 2013[6]. Two key conclusions of the report are:

- "An updated analysis shows that with existing resources and projected energy efficiency, the region's adequacy will fall short of the desired level by 2017. While new resources are expected to close this gap, the Council will continue to monitor regional resource adequacy."
- "The character of the region's power system is changing. Historically, needs for new resources were driven mostly by energy deficits. Today, however, needs for peaking

[4] http://www.bpa.gov/power/P/ResourceProgram/Index.shtml

[5] http://www.nwcouncil.org/

[6] http://www.nwcouncil.org/media/6391355/2013-01.pdf

> capacity and system flexibility are also emerging, expanding the focus of the region's planning and development of new resources to address peaking capacity and system flexibility."

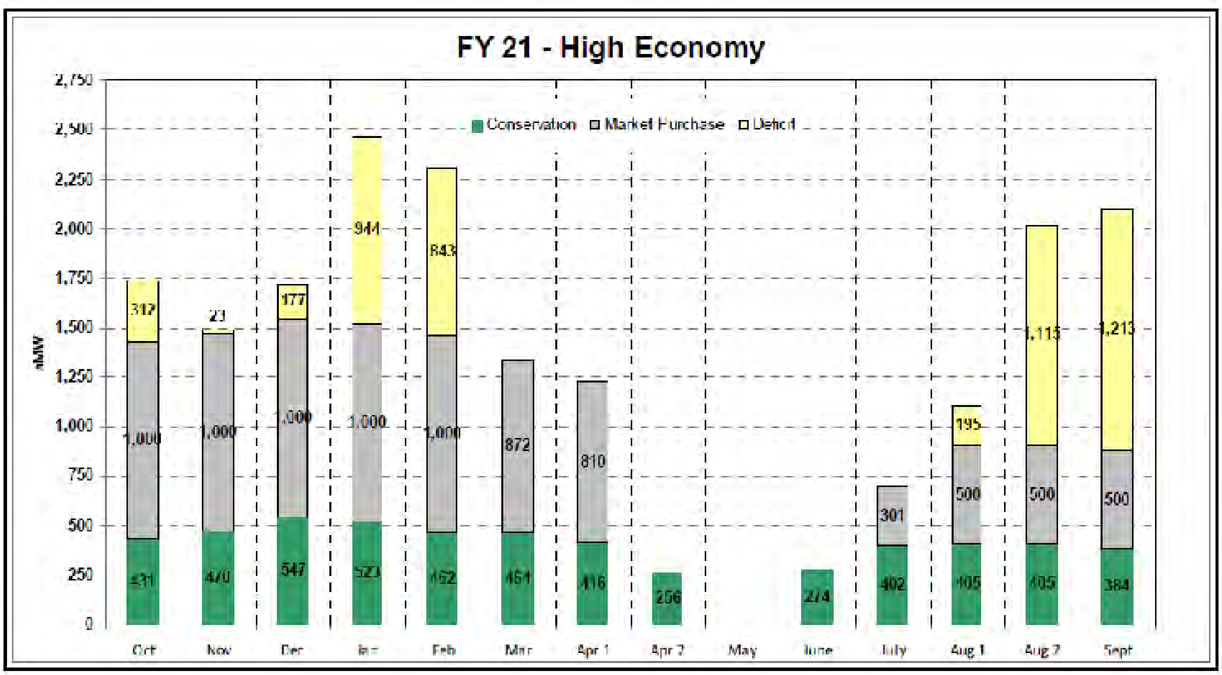
The Northwest Power Act of 1980 (section 4(e)) provides that the Council's Power Plan give priority to the following resources the Council determines to be cost-effective:

1. Conservation
2. Renewable resources
3. Generating resources using waste heat or of high fuel-conversion efficiency
4. All other resources

The Act directs BPA, in acquiring resources, to act consistent with the Council's Plan or otherwise follow the priorities set in the Act.

The most recent editions of the White Book (October 2012) and the Resource Program (February 2013) closely reflect analyses and conclusions in the Council's Sixth Power Plan. The White Book projects a 340 MW Average deficit in the BPA Federal System in 2017 followed by a 507 MW Average deficit by 2021. According to the Resource Program: "The analysis shows that under a variety of conditions and timeframes, BPA could need to supplement the existing Federal system generation to meet existing and projected obligations in the time period." However, the Resource Program proposes that deficits in 2021 will be mitigated by meeting conservation targets first and market purchases second. Figure B-1 illustrates the estimated deficits and projected BPA application of conservation measures and electricity market purchases in FY 21 for a high growth economy.

Figure B-1, BPA Federal Energy System Conservation and Market Purchases, FY 2021 High Economy Case



Source: BPA 2013 Resource Program, page 63 (Note that Conservation savings are achieved in all months but are shown here only where there is a projected deficit)

B.1.3 Analysis of Regional Power Planning

Although BPA is not planning to add additional capacity, there are several vulnerabilities in their planning that could easily lead to near term decisions to reverse that conclusion.

- Conservation targets

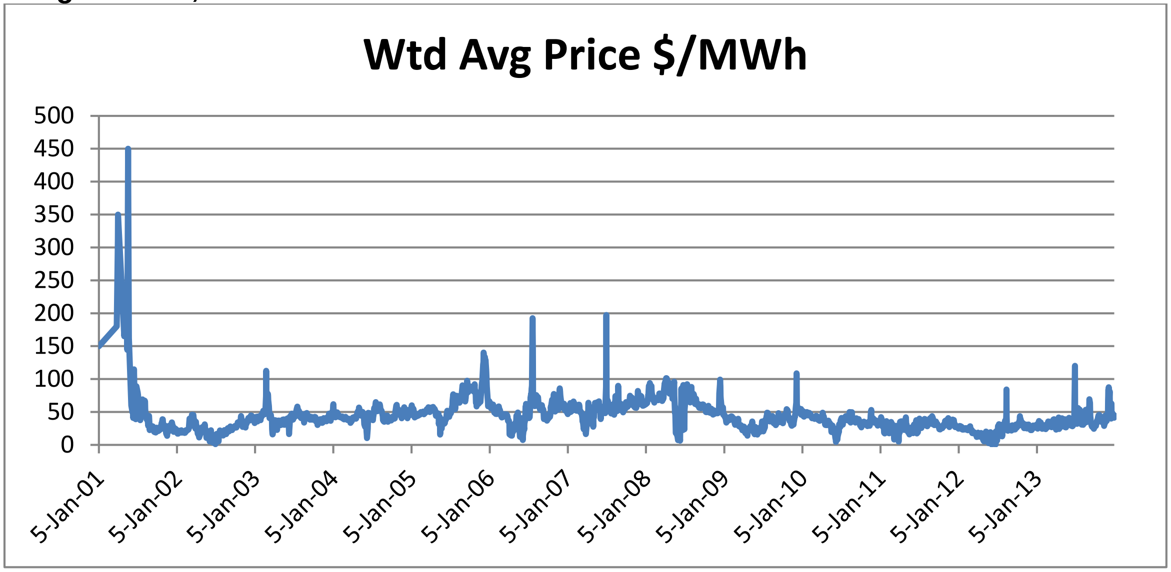
  The Sixth Power Plan and the recent Sixth Power Plan Mid-Term Assessment provide evidence that the current conservation programs are meeting or exceeding their goals thus supporting the expectation the conservation will be a major factor in mitigating future deficits. The average estimated levelized cost of implementing conservation efficiencies reported in the Mid-term Assessment is $18 per MWhr. Discussions with a local utility official indicate that further savings are possible in the region with installation of demand-metering and implementation of a demand price structure for both residential and industrial customers.

  While it is difficult to argue with the current success of conservation programs, it is possible and perhaps likely the conservation programs will show early success where “low hanging fruit” is harvested, but will plateau as the market saturates or economic resistance is met due to additional funds required to invest in new hardware or research and development. According to the 2013 Benton Public Utility District Conservation Potential Assessment, the levelized cost ($/MW-hr of electricity saved) of conservation projects will increase to as much as $100/MW-hr where it may be comparative to building new facilities such as an SMR or a natural gas plant. Regardless of the data, BPA is relying on projections of a current trend rather than promoting new and reliable fixed generation resources.

- Changes in availability/price of market purchases

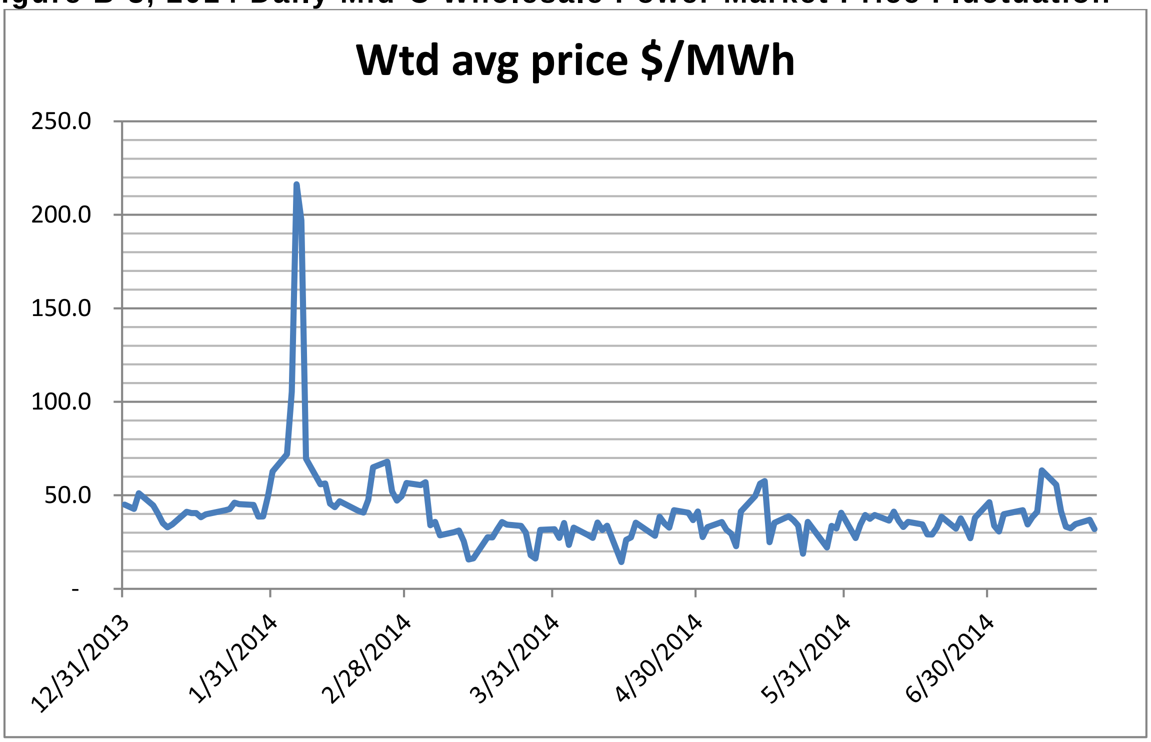
  Figure B-2 and Figure B-3 illustrate the variability of regional electrical power market prices at the Mid-C trading Hub in Portland Oregon. The figures shows that while the cost of wholesale electricity has been relatively low and attractive over the past couple of years, there were periods of time such as in 2001 when the price rose significantly such that SMR power would be very competitive. Even in today’s era of lower prices, Figure B-3 shows that major price swings for short-term purchases occur on a daily basis. The average cost of electricity at the Mid-C hub for 2014 thus far is approximately $40.8/MWhr for short-term purchases. Figure B-4 shows the cost of futures contracts for power. Note that this market is more stable and the prices are lower than the short-term market, ranging from an annual average of about $30/MWhr to about $40/MWhr in 2020.

Figure B-2, Historical Mid-C Wholesale Power Market Price Fluctuation



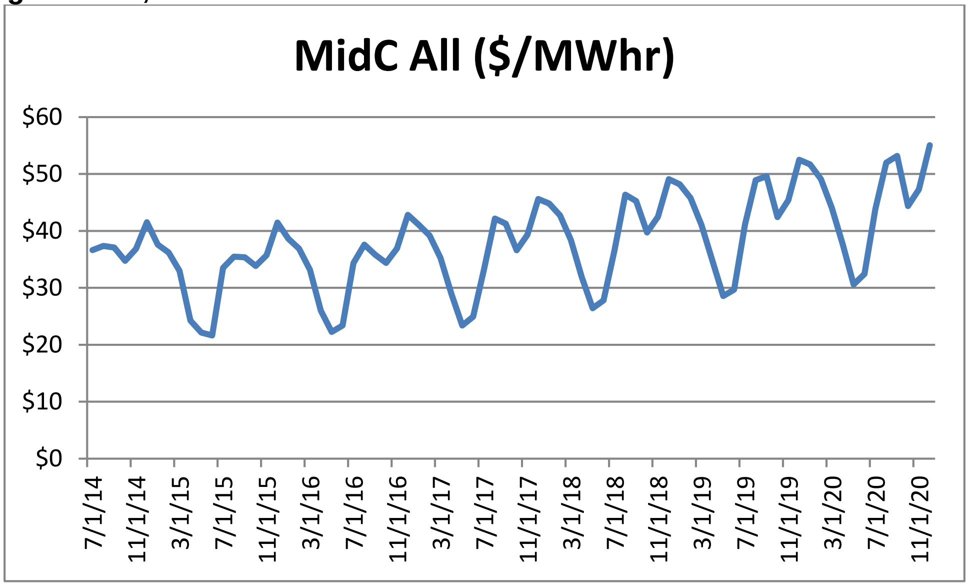
Source: U.S. Energy Information Administration Wholesale Electricity and Natural Gas Market Data

Figure B-3, 2014 Daily Mid-C Wholesale Power Market Price Fluctuation



Source: U.S. Energy Information Administration Wholesale Electricity and Natural Gas Market Data

Figure B-4, Futures Market Prices for Mid-C Electrical Power



Source: Data from The Energy Authority, 7/29/14

The following excerpt from the Sixth Power Plan Mid-Term Assessment Report, page 11 suggests that near term surpluses of power should keep prices low:

> "These and other factors (continued slow economic activity, modest growth in demand for electricity) have caused actual spot market prices for wholesale power supplies during the last several years to be at or even below the low end of the range of forecasts used for the Sixth Power Plan. For example, actual spot market prices for wholesale power supplies bought and sold at the Mid-Columbia trading hub averaged about $20 per megawatt-hour during July 2011 - June 2012. In contrast, average prices for calendar year 2008 were more than 250 percent higher. For all utilities, the depressed spot market prices for wholesale power are currently below the full cost of virtually any new form of generating resource."

In-depth analysis of historical data from the U.S. Energy Information Administration confirms the lower prices in the July 2011 – June 2012 timeframe ($24.7 per MWhr) but the data also shows that these prices were abnormally low compared to other years including 2014 (average price to date of $40.8 per MWhr for short-term purchases). On the other hand, Figure B-4 does show that utilities purchasing futures are currently realizing prices that may be less that the cost of a new generation resource.

The danger of relying on market purchases is that planners may rely too heavily on a current trend to continue. There are several factors that could reverse this trend. The Governor of Washington state has stated an intention to shut down the Washington State Centralia coal-fired power plants (a loss of over 1340MW) to reduce emission of greenhouse gases. In Oregon, the 550 MW Boardman coal-fired plant is scheduled to shut down in 2020. The Sixth Power Plan Mid-term Assessment also reports that California will lose 6659 MW of capacity due to new water standards in addition to the loss of 2200 of capacity when the San Onofre nuclear power plants shut down in 2012. While much of this has been factored into northwest power planning, there is no indication that the potential to shut down other western coal-fired plants has been factored into the market price predictions. It is clear that there is a level of uncertainty ahead in the future relative to electricity market prices.

Another factor affecting market costs in the Sixth Power Plan and BPA planning documents is the cost of natural gas. Both the Sixth Power and BPA documents address the variability of natural gas costs and the effect on the Northwest; however, the documents do not address extreme cases which could disrupt natural gas supplies or major changes in prices due to foreign pressures. Local utilities also point to the need to acquire balancing reserves to offset the intermittent nature of the contribution of wind power in their systems. As more wind power is added to the Northwest system, there will be more competition for balancing reserves and more pressure on market prices.

B.1.4 Conclusions

1. The Northwest Power and Conservation Council and BPA are projecting future shortages of power for the Northwest that exceed the output of an SMR. Both BPA and NPCC propose that the projected deficits can be mitigated through continuation of conservation programs and market purchases.
2. The BPA and NPCC proposal to mitigate deficits depends solely on the expectation that current trends in conservation and market pricing and availability will continue. While the conservation programs are successful today and current electricity market prices are generally reasonable, there are multiple conditions that could significantly jeopardize this approach. Utility representatives interviewed expressed doubt that the BPA proposal to rely on conservation and market purchases will mitigate future Northwest power deficits and would feel more comfortable depending on new facilities rather than mathematical trends.
3. Utilities would be well-advised to acquire access to a resource such as SMR power to achieve a more reliable supply of base-load power with stable fuel costs. SMR power could also provide some degree of load-following capability to offset the intermittent nature of wind power.

B.1.5 Actions

1. Participate in future Northwest Power and Conservation Council activities to incorporate nuclear power, specifically an SMR, into planning documents and ensure dependable approaches rather than only trends are proposed to meet Northwest Power needs. Request to be added to the NPCC Resource Strategies Advisory Committee.
2. Develop legislation that would revise the priorities of the Pacific Northwest Electric Power Planning and Conservation Act of 1980 to include nuclear power as a priority to reduce greenhouse emissions.
3. Monitor the analyses and conclusions in future releases of the Northwest Power and Conservation Council Power Plans and the follow-on BPA planning documents.
4. Interact with northwest utility advocacy organizations such as the Pacific Northwest Utilities Conference Committee, Northwest Requirements Utilities, Northwest Public Power Association, the Public Power Council and the American Public Power Association to exchange information related to new generation planning.

B.2 Estimated Hanford and City of Richland Power Needs

The DOE Richland Operations Office (RL) and the Pacific Northwest Site Office (PNSO) manage power planning and power purchases for DOE operations at the Hanford Site. RL currently uses 21 MW average while PNSO consumes approximately 12 MW average annually.

B.2.1 Richland Operations Office

The RL power needs are not expected to change significantly until the Hanford Waste Treatment Plant comes on line which is assumed to occur in 2022 for this study. At that time the RL peak load is estimated to increase to 80 MW peak with an average load of 60 MW (Figure B-5and Figure B-6). RL receives more than 90% of its power directly from BPA and the remainder from the City of Richland (for the southern facilities) which is also a BPA customer. BPA's average rate for power was 3.10 cents per kWh in 2013. The Hanford Site electrical energy consumption from BPA was about 185,630,000 kWh in FY2013. Transmission costs are separate and are roughly 11% of the power costs.

Figure B-5, Electrical Demand (ave MW) for RL and PNSO Projected to FY 2022

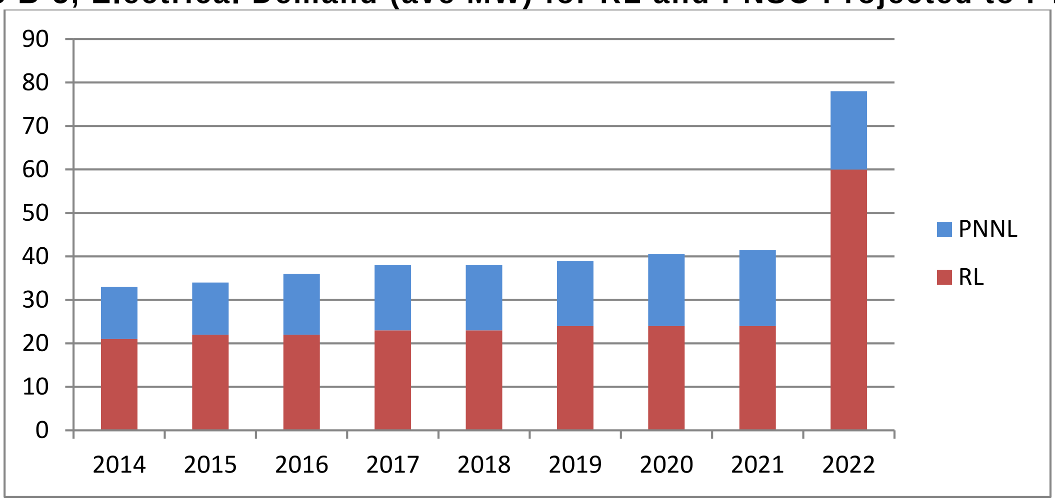
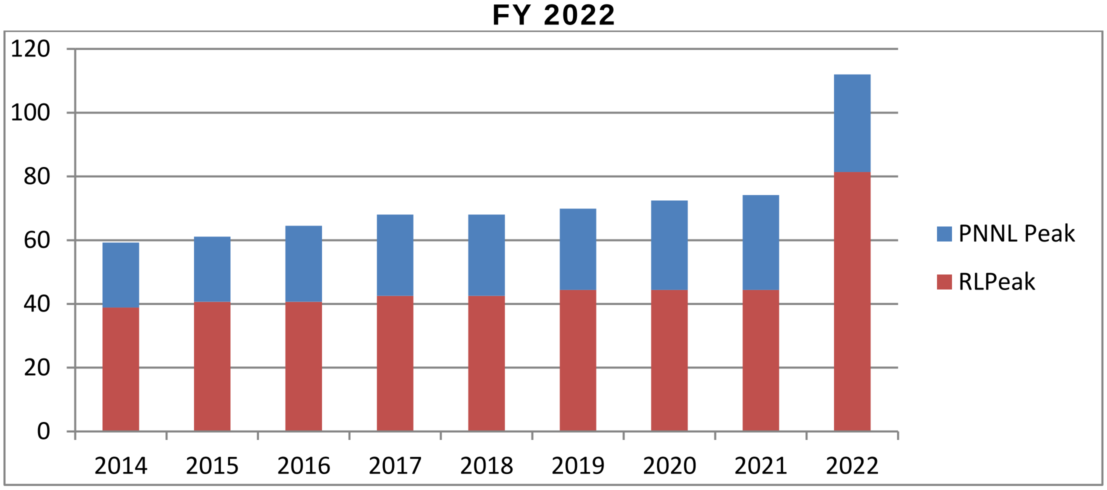


Figure B-6, Peak Electrical Demand (MW) for RL and PNSO Projected to FY 2022



In 1999 RL performed an electrical procurement options study which concluded BPA's power poses the lowest risk as well as the lowest price to RL. In 2008, DOE approved a "Justification for Other than Full and Open Competition" that allowed RL to enter into an Interagency Agency Agreement with BPA for BPA to provide power to RL. The current power and transmission agreements are effective from Fiscal Year (FY) 2012 through FY 2028 and the agreement guarantees an additional 70 MW of power above the current load as needed at the Tier 1 rate (See Section 3.2.1.1 Augmentation for Additional CHWM for DOE-Richland in the BPA document "Tiered Rate Methodology Supplemental Rate Proceeding, Tiered Rate Methodology" dated September 2009). It is possible that changes to the RL agreement with BPA for the current power supplied (Contract High Water Mark) would be subjected to BPA's rate hearing public processes but the election of the additional power is not. Note that Figure B-5and Figure B-6 show a growth of approximately 40 MW for RL.

The Energy Policy Act of 2005[7] and Executive Order 13423—Strengthening Federal Environmental, Energy, and Transportation Management dated January 26, 2007[8] set requirements for federal agencies to utilize renewable electrical energy. The Energy Policy Act establishes the following requirements:

> **SEC. 203. FEDERAL PURCHASE REQUIREMENT**
>
> (a) REQUIREMENT.—The President, acting through the Secretary, shall seek to ensure that, to the extent economically feasible and technically to the extent economically feasible and technically practicable, of the total amount of electric energy the Federal Government consumes during any fiscal year, the following amounts shall be renewable energy:
>
> (1) Not less than 3 percent in fiscal years 2007 through 2009.
> (2) Not less than 5 percent in fiscal years 2010 through 2012.
> (3) Not less than 7.5 percent in fiscal year 2013 and each fiscal year thereafter.

The Act defines renewable energy as:

> "electric energy generated from solar, wind, biomass, landfill gas, ocean (including tidal, wave, current, and thermal), geothermal, municipal solid waste, or new hydroelectric generation capacity achieved from increased efficiency or additions of new capacity at an existing hydroelectric project."

Executive Order 13423requires that at least half of the statutorily required renewable energy consumed by the agency in a fiscal year comes from new (placed into service after January 1, 1999) renewable sources. In a December 5, 2013 Memorandum to the Heads of Executive Departments and Agencies[9], the President further increased the goal to 20 percent of the total

[7] http://www.gpo.gov/fdsys/pkg/BILLS-109hr6enr/pdf/BILLS-109hr6enr.pdf

[8] http://www.gpo.gov/fdsys/pkg/FR-2007-01-26/pdf/07-374.pdf

[9] http://www.whitehouse.gov/the-press-office/2013/12/05/presidential-memorandum-federal-leadership-energy-management

amount of electric energy consumed by each agency during any fiscal year shall be renewable energy by 2020.

According to RL utility managers, the goal for federal agencies is applied at the agency level such that different goals may be set for each agency office as long as the overall goal is achieved. According to DOE's Office of Energy Efficiency and Renewable Energy (EERE), a Renewable Energy Working Group developed guidance for Federal agencies on what can be counted toward the Act's renewable energy goals as modified by Executive Order 13423. The Renewable Energy Working Group determined that federal agencies may directly purchase renewable electrical energy or may purchase Renewable Energy Certificates (REC) to count toward agency goals. According to EERE unbundled RECs (also known as green certificates, green tags, or tradable renewable certificates), represent the environmental attributes of the power produced from renewable energy projects and are sold separately from commodity electricity.

Given the higher cost of renewable energy, RL decided to meet these goals through the purchase of unbundled RECs from the Western Area Power Administration (WAPA). Currently, RL pays approximately $40K per year for their RECs. RL plans to continue the purchase of RECs to meet additional goals.

B.2.2 Pacific Northwest Site Office

Power needs projected by PNSO for Pacific Northwest National Laboratory and other Battelle facilities in north Richland are expected to grow steadily as the Laboratory adds new high performance computing capabilities and new facilities as they are constructed on the north end of the Laboratory. PNSO receives all electrical power from the city of Richland under standard City of Richland electrical utility billing practices; i.e. there is no formal Power Purchase Agreement with the City of Richland. The current demand is approximately 12 MW (ave) at a cost of $5.4M per year including transmission and system management costs. Figures B.2.1 and B.2.2 show the projected increase in electrical power needs through 2022. PNSO is also required to meet renewable energy goals and meets the requirement through purchases of RECs similar to RL.

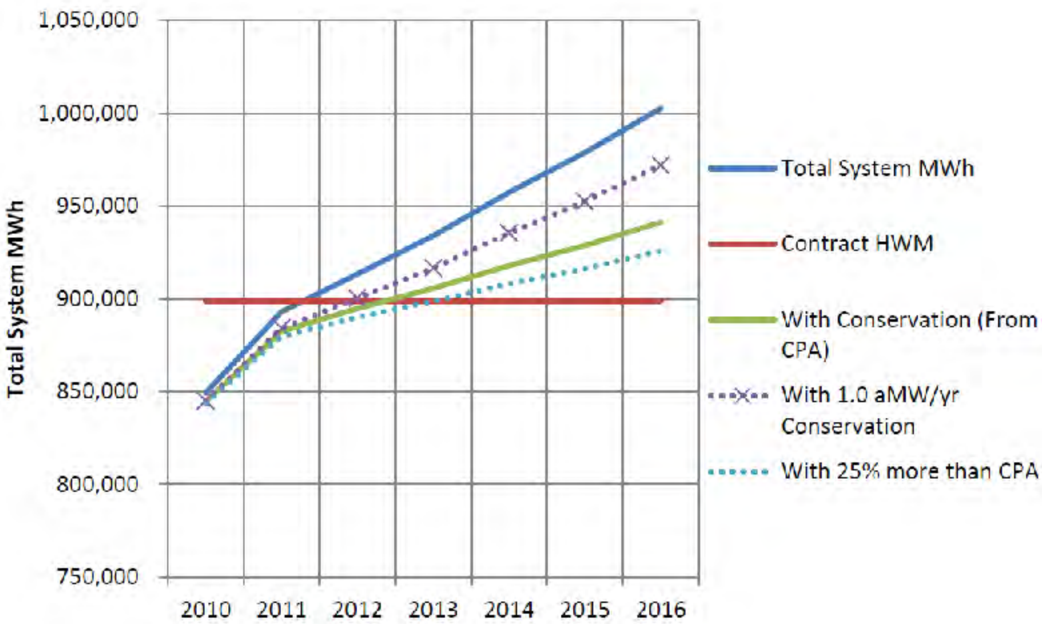
B.2.3 City of Richland

As of May 2013, the City of Richland averages 97 MW of electrical power usage with peaks of about 173 MW in both summer and winter. The City of Richland currently purchases electrical power from BPA. In 2012, the average cost of power was 3.4 cents/kwhr. Note that power purchased by PNSO is included in the total power used by the City of Richland.

The post-2011 rate period for BPA includes a two-tiered rate structure. The majority of Richland power will be provided by BPA at the lower Tier 1 rate. Power requirements above the Contract High Water Mark will be available at higher rates. Therefore, acquiring energy efficiency resources reduces the need for Tier 2 power. Figure B.2.3 shows the projected load forecast for the City of Richland with the current High Water Mark at 900,000 MWhr. Richland power needs currently exceed the High Water Mark; consequently Richland receives power from BPA through market purchases and a small amount from a contract established with a consortium of utilities called the Northwest Requirements Utilities.

The Washington State Energy Independence Act (EIA) will require that the City of Richland be achieving approximately 1.64 aMW per year of conservation resources by 2016[10], which is approximately four times the current levels. An estimated budget to acquire this level of conservation is approximately $4.6 million. Richland expects that the current suite of conservation programs as will be successful in reducing future loads per Figure B-7 and will meet the state goals when they become applicable, but will not drive down needs below the High Water Mark. In addition, the EIA requires that Richland provide three percent of its load with qualifying renewable resources by 2018 growing to fifteen percent by 2026. Like RL and PNSO, Richland will likely purchase RECs to meet this goal, but would rather be purchasing firm energy from a competitive SMR instead of paying for a product that delivers no energy.

Figure B-7, RES Load Forecast and Impact of Conservation



Source: RICHLAND ENERGY SERVICES—ENERGY EFFICIENCY AND RENEWABLE RESOURCES PLAN 2012-2017 page 10 (Note: CPA is the 2010 Conservation Potential Assessment

B.2.4 Conclusions

1. The combined RL and PNSO electric power need for 2022 is approximately 75 MW ave with a peak requirement above 100 MW. The peak requirement would be sufficient to justify siting an SMR at Hanford to meet future power needs.
2. With current average loads in the 100 MW range, and future power loads projected to exceed the High Water Mark, the City of Richland (including PNSO) could also be a viable candidate for utilization of SMR electrical power.
3. RL, PNSO, and Washington State utilities are required to utilize a growing share of renewable power to meet their future loads. Current practice to meet these goals is to purchase unbundled RECs which deliver no power or to purchase some wind power which is

[10] http://www.ci.richland.wa.us/DocumentCenter/View/2470

intermittent and requires off-setting purchases of balancing reserves. RL, PNSO, and Washington State utilities would better serve their customer base by purchasing competitive green power from an SMR.

B.2.5 Actions

1. Recommend that Federal and/or DOE guidelines to agencies incorporate reduction of greenhouse gas as an alternative to the goal to purchase renewable energy. While the impact of the current requirements to purchase renewable energy or RECs is a minor consideration for Hanford planning, reconsideration of the Federal Energy goals to include reduction of greenhouse gas would result in purchasing SMR electricity more attractive and would support meeting other national objectives.
2. Include SMR Power in State-Mandated Energy Portfolio Policies. Several states have enacted measures to move power consumption toward clean or renewable power sources. For instance, the state of Washington will require that the power portfolios of major utilities include no less that 15 percent renewable energy by 2020. Tax incentives for generation and/or use of SMR power is another example. All states should consider these approaches for the clean energy produced by SMRs.

B.3 Meeting DOE and Regional Power Needs with an SMR

B.3.1 Meeting DOE's Hanford Needs with an SMR

As identified in Section B.2 of this report, there is a clear need for power at Hanford and the City of Richland.

With current Tier 1 rates of $30/MWhr available to RL, there is no immediate economic incentive for RL to incorporate SMR power into future planning. However, future competition for Tier 1 power between meeting residential and other humanitarian needs and meeting federal government obligations could lead to a change in planning scenarios whereby utilizing SMR output could become very attractive. Previous sections indicate that lack of BPA action to acquire new resources may also incentivize DOE to consider supporting a Hanford SMR to ensure DOE programs will have adequate resources to meet legal obligations to operate the Vitrification Plant in the future. On a national level, demonstrating new energy technology and supporting critical DOE programs at Hanford with SMR power creates a highly positive environment for siting an SMR at Hanford. The same rationale could also apply to PNSO. Supporting Waste Treatment Plant operation with green and reliable power from an SMR may also appeal to Washington State officials.

If DOE were to decide that DOE programs at Hanford will use Hanford SMR power, the bilateral Inter-Agency Agreement between DOE and BPA would need to be modified. This may require a public participation process if it is considered a change to the Tiered Rate Methodology set in BPA's 2008 Regional Dialogue (RD). The current agreements apply to RL's current power usage (High Water Mark). It would seem likely that RL may benefit from avoiding changing agreements reached in the Tiered Rate Methodology and elect to only utilize SMR for the 40 MW (ave) power above their current High Water Mark.

RL or PNSO direct purchases of power from a Hanford SMR would introduce complexities into their management of power through the need to balance loads and resources at any given time. BPA and other organizations offer services for resource shaping. It would seem more likely that

PNSO would continue to purchase power through the City of Richland and Richland could purchase SMR Power (See Section B.3.3). Likewise, it may be beneficial for RL to purchase SMR power through BPA and continue to use BPA's load shaping services.

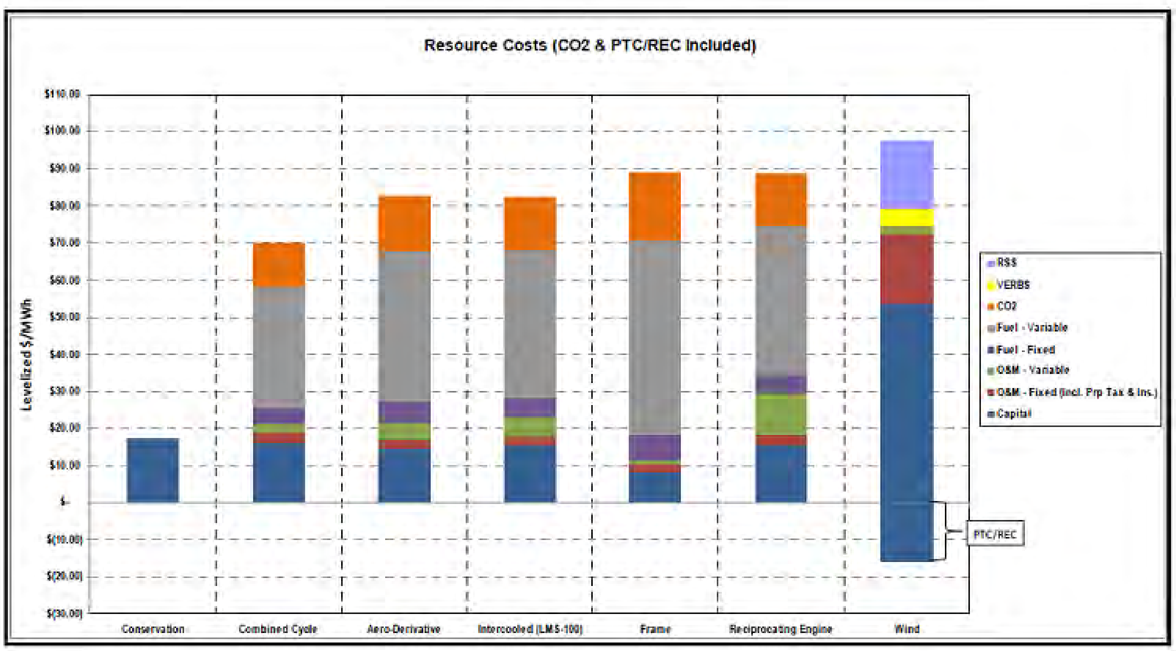
B.3.2 Selling Power to Bonneville Power Administration or Other Entities

The 2013 Resource Program evaluates alternatives for new capacity. Nuclear power is not included in the analysis. This is consistent with the Sixth Power Plan which makes only a minor reference to nuclear power in the plan Summary as follows:

> "Along with the smart grid, other technologies may be able to provide power when it is needed with low cost, low risk, and low emissions. In the future, the region may find greater value in power generated by geothermal resources, ocean waves, tides, gasified coal with carbon sequestration, advanced nuclear or currently unknown technologies."

Although not planning to add new capacity to the BPA Federal System, BPA also evaluates potential technologies for future capacity additions including the potential cost of adding them to the system. Figure B-8 illustrates BPA's projected electrical costs for conservation, natural gas, and wind assuming expansion of a carbon tax such as that to be imposed in California and assuming continuation of current tax credits. In current dollars, conservation is by far the lowest cost option at a projected cost of $20/MWhr or less followed by natural gas plants at $70 - $90/MWhr when the carbon costs are included. Wind generation is projected to cost approximately $100/MWhr after tax credits are applied and cannot meet peaking power needs effectively. BPA is reluctant to count on wind power for future capacity additions because of the need to provide for balancing reserves.

Figure B-8, Levelized Cost of Energy with Carbon Costs, Production Tax Credits and Renewable Energy Credits



Source: 2013 BPA Resource Program, page 51

An SMR which could sell electricity at a rate of $85 - $100 per MWhr would be in the competitive range for BPA to consider as new resource capacity. This is a price range that Energy Northwest has suggested in the past for SMR electricity.

If BPA were to consider adding new capacity such as an SMR to the federal system, current requirements in the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Act) would lead BPA to work closely with Power Planning Council and stakeholders in the Northwest. The Northwest Power Act requires that BPA follow specific procedures if it proposes to acquire the output of a "major resource." A major resource is defined as one with a planned capability greater than 50 aMW and that is acquired for more than five years. If BPA were to propose to acquire a major resource, BPA would need to ensure that the proposed acquisition is consistent with the latest version of the Council's Power in a public process. While nuclear power is not listed as a priority under the Act, the priorities of the Act are only tie breakers when alternative resources have equal cost.

Unless BPA re-considers their conclusions on acquisition of new resources, it does not appear that near term planning should assume that an SMR would be incorporated into the BPA Federal System and marketed through BPA. The procedures for new acquisitions to the Federal System and the other organizations involved could also been seen as obstacles for achieving decisions in a time frame consistent with DOE's SMR demonstration program.

While BPA may not add an SMR to its managed Federal System, BPA could very likely purchase SMR power through what is called the Vintage Products. The Vintage Products are essentially Power Purchase Agreements BPA establishes with one or more power producer and the power is provided to BPA customers needing power over the quantity of Tier 1 power (High Water Mark) guaranteed in their contract with BPA. The process of developing Vintage Products can involve a group of utilities requesting a specific type of power such as the current wind power Vintage Product or possibly SMR power in the future. Upon receiving a request from utilities for a Vintage Product, BPA competitively negotiates the price, establishes the Power Purchase Agreement independent of the Tiered Rate Methodology public comment and hearing processes, and provides the power to participating utilities at a price contingent upon the Vintage Product Power Purchase Agreement.

References

Volcovici, V. and DiSavino, S. (2014). *Business & Financial News, Breaking US & International News | Reuters.com | EPA Nod to Nuclear in Carbon Rules, as Generators Fear Closure*. [online] Reuters.com. Available at: http://www.reuters.com/assets/print?aid=USL1N0OF24O20140530 [Accessed 30 May. 2014].

Appendix C

Future Cost of Power in the Northwest

Contents

Tables

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SELLING POWER TO NORTHWEST UTILITIES

Other utilities in the Northwest could also consider adding an SMR to their systems through acquiring and operating the plant or through a Power Purchase Agreement with another constructor/operating organization.

Energy Northwest would be a logical choice as an owner/operator of an SMR given the significant advantages of co-location with their Columbia Generating Station and the ability to serve a large customer base. As a Washington state, not-for-profit joint operating agency, Energy Northwest comprises 27 public power member utilities from across the state serving more than 1.5 million ratepayers. However, there may be some obstacles to Energy Northwest as an owner.

Energy Northwest is governed by a Board of Directors and an Executive Board that both oversee the Energy Northwest corporate management team. According to RCW 43.52.374, "Operating agency executive board — Members — Terms — Removal — Rules — Proceedings — Managing director — Civil immunities — Defense and indemnification"

> "the management and control of an operating agency constructing, operating, terminating, or decommissioning a nuclear power plant under a site certification agreement under chapter 80.50 RCW is vested in an executive board established under this subsection and consisting of eleven members."

Under this statute, the Board of Directors which is comprised of individual member utilities who would bear financial responsibility would not have control of an SMR construction project. This could become an issue should Energy Northwest consider acquiring a new large generation resource, particularly nuclear power since some of the member utilities represent segments of the Northwest not favorable toward nuclear power. On the other hand, if a private firm or DOE were to fund construction of the plant and assume overall responsibility, both the Executive Board and Board of Directors may see advantages to being involved in operating new generating capacity and having the option to purchase power rather than being required to purchase or market additional nuclear power if they were the owner. The option of Energy Northwest operating a Hanford SMR for DOE or a private organization would be attractive given the wealth of Energy Northwest's experience in operating power-producing reactors in addition to the economic benefits of co-location. In so far as Energy Northwest is a participant in one of the current proposed SMR projects which would be built elsewhere, it is clear that they have an on-going interest in SMR type facilities.

Outside of the Energy Northwest organization of utilities, individual utilities are very viable candidates for purchasing Hanford SMR power at a competitive price with new generation resources. Utilities in the Northwest served by BPA (including the Energy Northwest member utilities) have contractual agreements with BPA to purchase electric power in accordance with the Tiered Rate Methodology set in BPA's 2008 Regional Dialogue (RD). The methodology established three different approaches to buying power, Load-Following, Slice/Block, and Block Products as described in BPA's "Regional Dialogue Guidebook," dated June 4 2010.

Most Northwest Utilities have selected the Load-Following Product whereby BPA guarantees Tier 1 Power at a High Water Mark amount and above that BPA provides a combination of short-term market, Vintage, Load Growth, and Load Shaping products (Tier 2) to meet needs above the High Water Mark. Utilities have pre-determined dates to buy the Vintage Products and may request that BPA buy specific types of power such as wind power. Utilities may also elect to use non-Federal resources to serve a portion of the load, but they must do so consistent with Section 5(b)(1) of the Northwest Power Act. For example, the City of Richland has a contract for a small amount of power through the Northwest Requirements Utilities organization.

The remainder of utilities participating in the BPA program has selected the Slice/Block Product whereby BPA guarantees a block amount of flat-shaped power over the year and a slice amount that accounts for times of higher electrical usage. Power needs above Slice/Block High Water Mark amounts are the responsibility of the utility. Most of the Slice/Block customers have contracted with The Energy Authority, a Florida-based firm with an office in Bellevue, Washington. On a daily basis, The Energy Authority uses a combination of longer-term and short-term market purchases to meet needs above the High Water Mark.

Both the Load-Following and Slice/Block BPA customers could become candidates for purchasing competitive SMR power. The Load-Following utilities can request that BPA prepare a Vintage Product with SMR electrical power for incorporation into their Tier 2 resource package. Both the Load-Following and Slice/Block utilities could also obtain SMR electric power through a group contract package through an organization such as Northwest Requirements Utilities. One concern with marketing SMR power to utilities in the BPA system is that a long lead time is required to commit to BPA products. The owner/power marketer for SMR power may have to establish terms and conditions for a power purchase agreement before final SMR power costs are known.

The City of Richland and the Franklin PUD both indicated that they would be very interested in purchasing SMR power provided at a competitive rate in the future. They recognize that SMR nuclear power would offer several advantages over renewable power such as wind in that it can be used as base load and to some degree could be load-following. They also note that SMR fuel prices offer greater stability than natural gas and that SMR electrical power costs are clearly more stable and reliable than market purchases. Although the Benton County PUD projects a power surplus for several years, they too would seriously consider SMR power if it could be used in lieu of renewable power to meet the requirements of the Washington State Energy Independence Act.

Conclusions

1. The local Hanford area including DOE-RL, PNSO, and the local utilities could benefit significantly from securing power from a Hanford-based SMR to meet emerging needs, especially those above the Tier 1 High Water Mark for utilities.
2. Within the next five years, RL will make a decision on electing to commit to purchasing additional power from BPA. Regional utilities will also be making commitments to buy power from BPA or through other entities that will last well into the 2020's.
3. The following table, Table C-1 provides a summary of the feasibility of establishing Power Purchase Contracts to market Hanford-based SMR electrical power.

Table C-1, Summary of Options to Market Hanford SMR Power

Organization	Potential Participation in SMR Project	Comments
DOE Richland Operations (RL)	Purchase power either directly from SMR or through BPA	Most likely to retain current Tier 1 level of power purchase from BPA, but could meet expected 40MW of growth with SMR power benefitting national, Northwest, and local RL interests.
DOE Pacific Northwest Office	Included with City of Richland, but could purchase power directly from SMR	Most likely scenario would be to continue purchasing power through City of Richland
Bonneville Power Administration	Could "acquire" an SMR as part of Federal System or offer SMR power to utilities via a Vintage Product Power Purchase Agreement	BPA does not currently plan to acquire new resources for the Federal System. At the request of utilities in the BPA system for SMR power, BPA would establish an SMR Vintage Product. This is a very credible path forward for marketing SMR power.
Energy Northwest	Energy Northwest could become an owner operator or could serve as the operator for an SMR.	The current structure of the Executive Board and Board of Directors might be an obstacle to Energy Northwest ownership of a Hanford SMR. It would be more likely that Energy Northwest serve as an operator.
Northwest Utility on BPA Load-Following Contract (e.g. City of Richland)	Purchase power either directly from SMR or through BPA	Most likely scenario would be for utilities to request BPA to establish a SMR Vintage Product.
Northwest Utility on BPA Slice/Block Contract (e.g. Franklin and Benton County Public Utility Districts)	Purchase power either directly from SMR or through BPA	A likely scenario might be for a number of Slice/Block utilities to utilize a power marketing agency (such as The Energy Authority) to establish a PPA with the SMR owner.
Northwest Requirements Utilities (or similar organization with member utilities)	Act as a representative for member utilities in establishing a PPA for SMR power to be shared by member utilities.	Establish a PPA with SMR owner to provide power to member utilities

Actions

1. Meetings with TRIDEC and DOE officials in Washington, D.C. should be conducted to address DOE involvement in a Hanford SMR such as establishing a PPA to use SMR power. DOE sites across the US have large annual power needs to operate high use facilities such as WTP and the many large computer systems and particle accelerators located at DOE's national laboratories. DOE is in a position to mandate that the power from initial SMRs be purchased for their needs using long-term PPAs at prices that justify financing. This policy could also be extended to the Department of Defense and other federal agencies with a target of purchasing 50-70 percent of the power produced by the first three to four SMRs.

2. While BPA may not be currently in a position to consider a Hanford SMR as an acquisition in their system, BPA should be kept involved in SMR planning in accordance with their role in Northwest power planning. Both DOE and BPA could benefit from adding SMR power to their systems to provide a higher rate of confidence that future regional needs could be met.
3. Determine critical dates for utility decisions on power purchases
4. Survey Northwest utilities to determine willingness to participate either in a Vintage Product or Power Purchase Agreement established by a power marketing organization.

Appendix D

Base Cost of Construction

Operation of an SMR and WNP-1 Site Utilization and Estimated Cost Savings

Characterization and Licensing Approach and Cost Savings at WNP-1

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Contents

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BASE COST OF CONSTRUCTION AND OPERATION OF AN SMR

Reference

Atkinson, D. (2013). *The Future of Nuclear / Small Modular Reactors, Energy Northwest Member Forum XVI*, Kennewick, WA.

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2013

MEMBER FORUM XVI

ENERGY IN MOTION

ENERGY NORTHWEST

ENERGY IN MOTION

MEMBER FORUM XVI

Dale Atkinson

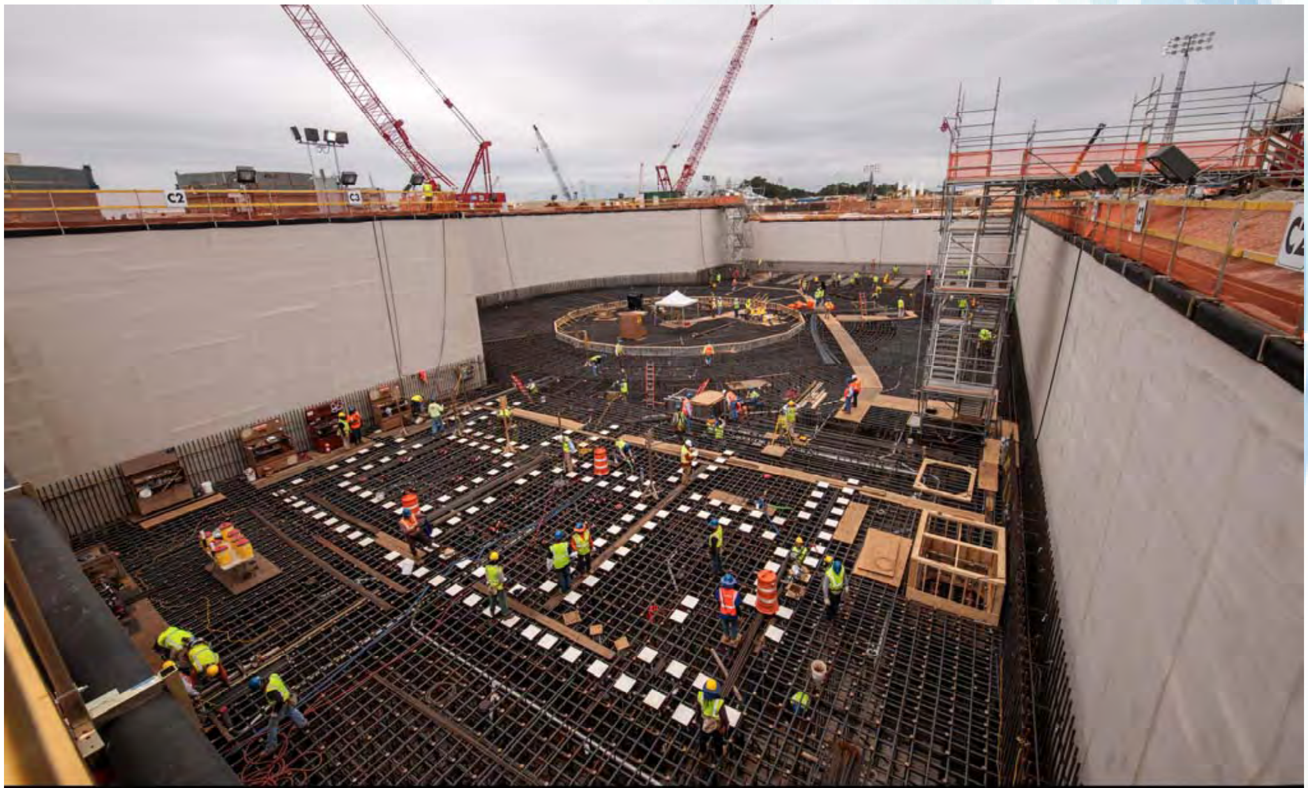
The Future of Nuclear / Small Modular Reactors

ENERGY NORTHWEST

Current Status of New Nuclear Power

- **4 new reactors being built:**
  - Vogtle 3 & 4 (Georgia)
  - Summer 2 & 3 (South Carolina)
- **All above are AP1000 design.**
- **Watts Bar 2 to be completed (Construction was halted in 1988):**
  - Target date: December 2015
- **173 new reactors are planned for construction by 2030 internationally.**
- **70 are presently under construction (30 in China alone).**

Vogtle 3 Nuclear Island – October 2013
Startup 2017 – 1117 MWe



Plant Vogtle Unit 4 nuclear island

October 2013

New Nuclear Power Plant Considerations

- Capital Expense - $2.5B (12 module SMR, 540MWe) to $7B per unit (1117MWe AP1000).
- Time to first positive cash flow:
  - Time to construct overall
  - Time to construct to first generation
- Licensing:
  - New designs require NRC certification - $800M-$1B
- Cost competitiveness:
  - Natural gas prices/renewables production tax credits
- Carbon Free.
- Base Load – Some Load Following/Response Capability.
- Public Acceptance.

Small Modular Reactor Advantages

- **Less capital - $2.5B for 540MWe.**
- **Simpler construction.**
- **Simpler operation and maintenance.**
- **Passive safety features.**
- **Scalable – Modules can be built as needed.**
- **First module generates electricity (and income) prior to all modules being complete.**
- **Reasonable response to generation needs (some load following).**
- **Small emergency planning zones – if allowed.**

ENERGY NORTHWEST

Energy Northwest SMR Interest Group

- **Made up of public and private entities.**
- **Purpose to stay aware of SMR technology, costs, benefits.**
- **Determine when and if appropriate to include new SMR construction in the energy portfolio.**
- **Status:**
  - **Selected NuScale as the SMR of choice if we were to build today**
  - **Tracking SMR development for potential inclusion in integrated resource plans**

DOE Funding Opportunity for SMRs

- **2012 -DOE announced $452M in funding for SMR development.**
- **Round one: $150M award to Babcock & Wilcox - mPower:**
  - **TVA Clinch River**
- **NuScale has applied for funding in the second round:**
  - **Idaho National Lab site**
- **The second round of applications is overdue for a decision.**

Energy Northwest and NuScale

- **NuScale's application :**
  - **Idaho National Lab site**
  - **Energy Northwest signed on to potentially provide operating and maintenance**
- **The DOE funding, if granted will help complete NRC design certification for the NuScale SMR.**
- **Actual first construction will depend on the owner and/or power purchase agreements.**
- **Energy Northwest continues to evaluate the former WNP-1 and WNP-4 sites for new construction.**

SMR Analysis

- **Determine a set of conditions where Small Modular Reactors are cost competitive when compared to a natural gas combined cycle (NGCC)power plant.**

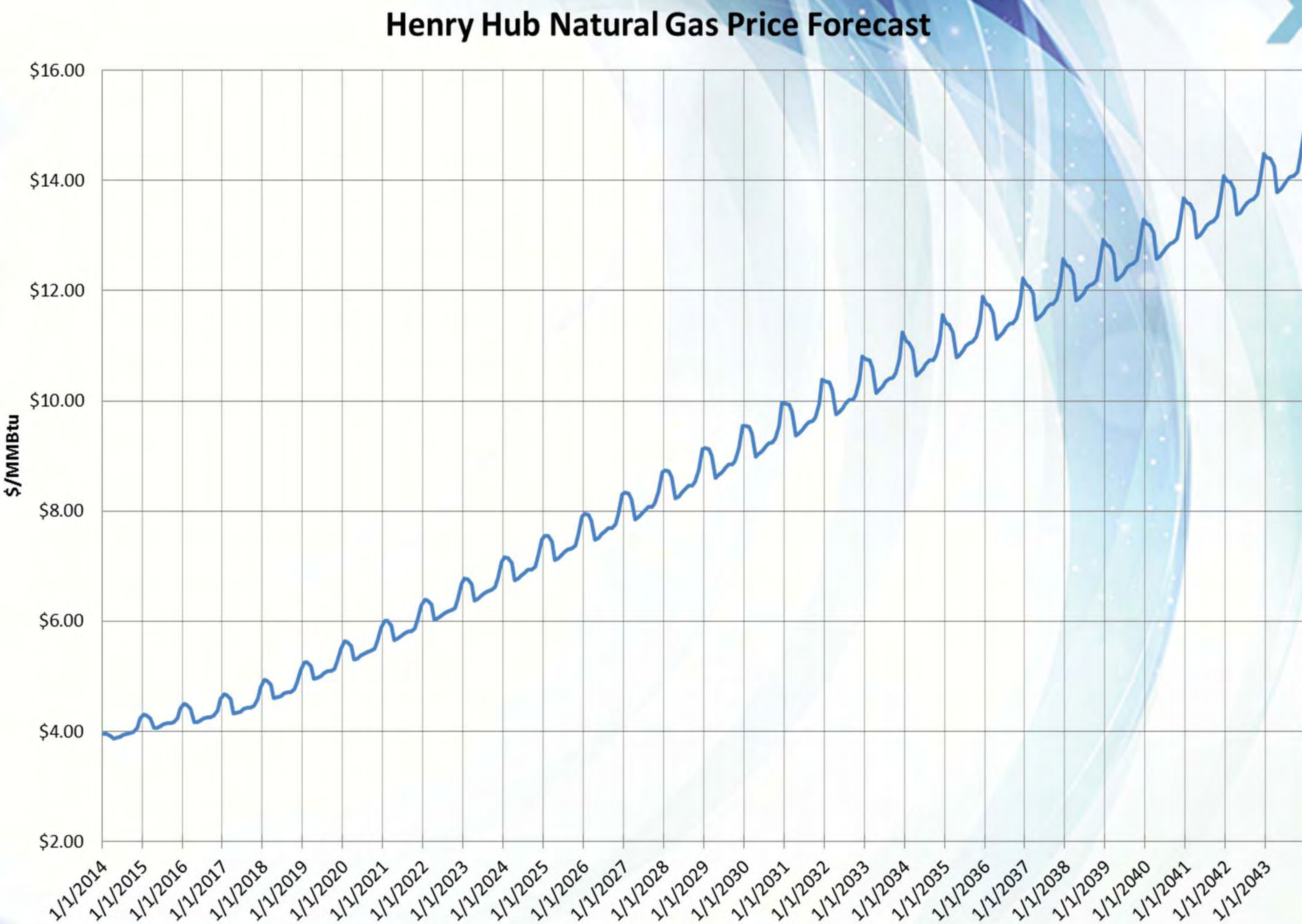
NGCC Key Assumptions

- 30-year Natural Gas Price Forecast is Accurate.
- Capital: 100% Debt Financed at 5% Interest.
- Plant Capacity Factor: 96%.
- Initial Greenhouse Gas Costs: $15/ton.
- O&M and GHG Cost Escalation: 3%.
- Project Life: 30 years.

Henry Hub Gas Prices 1993-2013

Oct 14, 2013, Reuters Reports:

- "Today the Henry Hub prices are in one of the low price cycles and below replacement cost," Richard Guerrant, ExxonMobil's global vice president for LNG, told the World Energy Congress in South Korea.
- ConocoPhillips executive vice president Don Wallette, speaking at the same panel discussion, said: "I think there is a misperception out there that with Henry Hub sales from $3.50 we can land LNG in Asia for $11, $12 (per million British thermal units)."
- "Over time the arbitrage is going to be consumed ... and you can expect a convergence of prices."



ENERGY NORTHWEST

ENERGY IN MOTION

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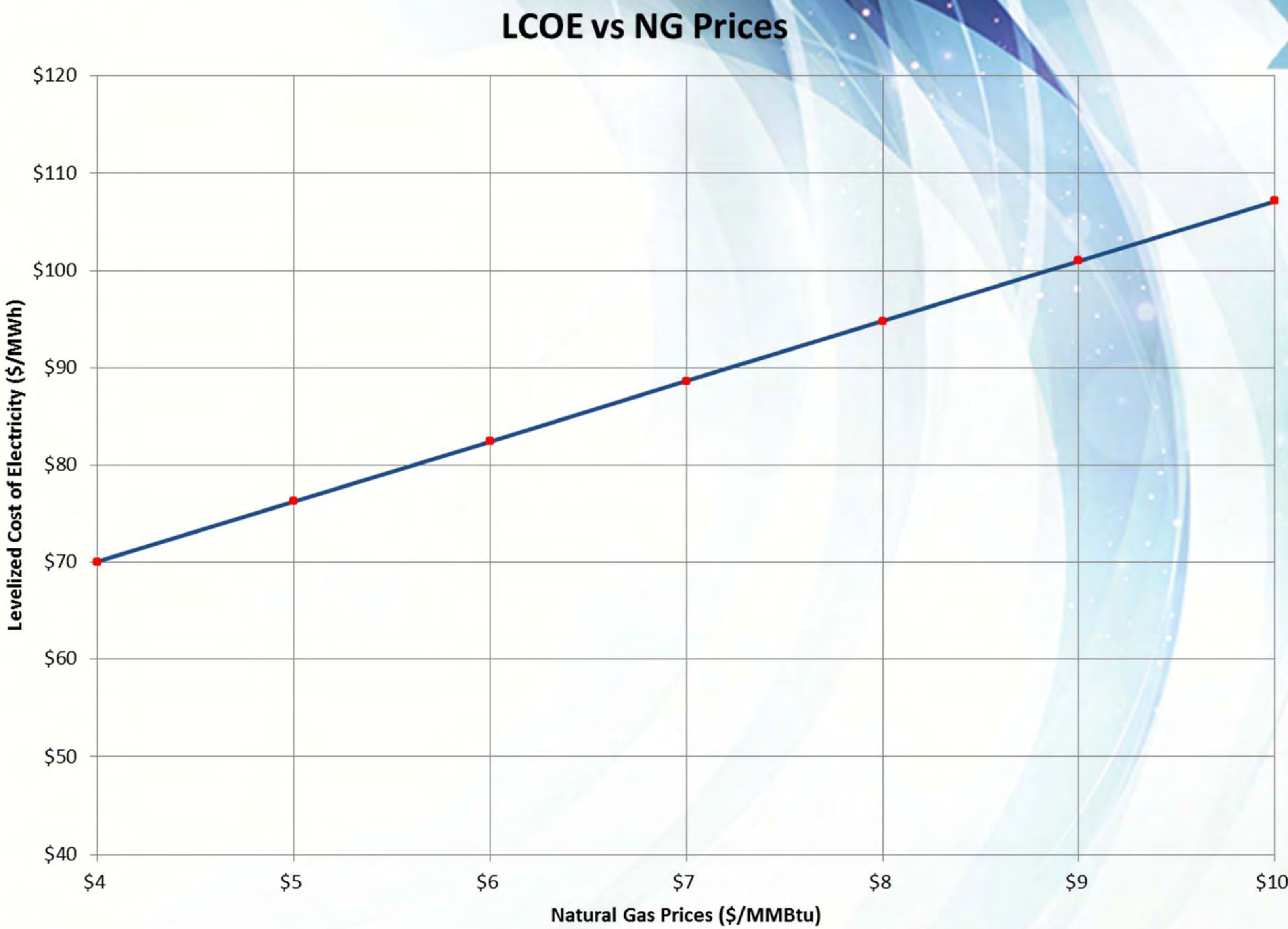

ENERGY NORTHWEST

Results

- **SMRs should be considered for resource plans ~10 years prior to forecasted gas price exceeding $6.5/MMBtu assuming:**
  - **$15/ton CO2 fee**
  - **$85/MWh SMR levelized cost**
- **Current estimates indicate that SMRs should be considered in resource plans after 2014.**

WNP-1 SITE UTILIZATION AND ESTIMATED COST SAVINGS

Hanford Small Modular Reactor Study

Study Number 29712-018-RPT-001

**ADEQUACY OF SITE STRUCTURES FOR SMR USE
AND ESTIMATED COST SAVINGS**

PREPARED FOR

**TRI-CITY DEVELOPMENT COUNCIL (TRIDEC)
KENNEWICK-PASCO-RICHLAND, WASHINGTON**

URS Corporation
510 Carnegie Center
Princeton, NJ 08540-6241

Revision: A2 Status: Preliminary

STUDY REVISION PAGE

Project Name:	Hanford Small Modular Reactor Study	Discipline:	Project Management
Client:	Tri-City Development Council	Project Number: 29712-018	

Latest Revision: A2

Revision Signatures

Prepared by	Date		
Prepared by	Date	Approved by (PM)	Issue Date

Status	Rev. No.	Date	Prepared By	Pages	Description of Changes
Prelim	A2	07/03/14	BA/RG		First draft

TABLE OF CONTENTS

Executive Summary

The Tri-City Development Council (TRIDEC) for the cities of Kennewick, Pasco and Richland in the State of Washington has expressed interest in promoting the construction of a Small Modular Reactor (SMR) at the abandoned Washington Nuclear Power Plant Unit No. 1 (WNP-1) site located within the Hanford Nuclear Reservation about 10 miles north of Richland, Washington.

This Study Report focuses on the initial assessment of adequacy of the existing WNP-1 facilities – some of which were essentially completed, and on the determination of what cost advantages could be realized from the construction and operation of a SMR at that site.

A one-day site visit that included interviews with Energy Northwest personnel was dedicated to the acquisition of information for project initiation. Very limited data is available at this time for an in-depth analysis of the adequacy of WNP-1 structures, systems and components for SMR utilization. Thus, the results of this study are preliminary and conservative.

One initial conclusion is that, due to relatively mild climate conditions at the WNP-1 site, the structures and components left behind after the cessation of construction are in very good condition and would require only minor refurbishments for SMR utilization over a 60-year operating life. In fact, many of the facilities continue to be used by Energy Northwest for various projects and to support the demolition of WNP-1 and WNP-4 structures and systems.

A proposed SMR will not occupy the major existing WNP-1 structures (containment building, safety related support structure and turbine pedestal). The SMR project would utilize approximately 40 acres of the original WNP-1 site and take advantage of portions of the established infrastructure, structures and systems.

Using a high-level estimating methodology, based on the 587 MWe PWR model in DOE's Energy Economic Data Base (EEDB), the existing portions of the WNP-1 site that could be repurposed to support SMR operations would result in potential savings of approximately $68 million. Facilities that can be initially utilized as temporary construction facilities and later used for various SMR operations would offer a potential savings of nearly $72 million. The overall potential cost savings could represent close to 6% of the projected base overnight construction cost of a generic SMR plant with a ROM overnight construction cost of $2.3 billion.

In view of these results, the study recommends that a more detailed analysis of costs be conducted that would include additional technical data from proposed SMRs that can be matched to the existing WNP-1 facilities. This recommendation is contingent on the determination that the cost of producing electricity (as calculated by others) would be competitive within the Northwest region of the U.S.

ACRONYMS AND ABBREVIATIONS

CWPH	Circulating Water Pump House
DOE	U.S. Department of Energy
EEDB	Energy Economic Data Base
Hanford	Hanford Nuclear Reservation
LIGO	Laser Interferometer Gravitational-Wave Observatory
MCCs	Motor Control Centers
MWe	Megawatts electric
NRC	Nuclear Regulatory Commission
PWR	Pressurized Water Reactor
SMR	Small Modular Reactor
SSCs	Structures, Systems, and Components
TRIDEC	Tri-City Development Council
WNP-1	Washington Nuclear Power Plant Unit No. 1
ROM	Rough-Order-of-Magnitude

1. Introduction

The Tri-City Development Council (TRIDEC) for the cities of Kennewick, Pasco and Richland in the State of Washington has expressed their interest in promoting the construction of a Small Modular Reactor (SMR) at the abandoned Washington Nuclear Power Plant Unit No. 1 (WNP-1) located within the boundaries of the Hanford Nuclear Reservation (Hanford) about 10 miles north of Richland, Washington.

Hanford is undergoing a major environmental cleanup. The site also hosts a commercial nuclear power plant, the Columbia Generating Station (formerly WNP-2) owned and operated by Energy Northwest, and various centers for scientific research and development such as the Pacific Northwest National Laboratory and the Laser Interferometer Gravitational-Wave Observatory (LIGO).

TRIDEC believes that the history of the Hanford Nuclear Reservation in the development and utilization of nuclear energy, and the richness of resources available in the Tri-cities area with experience in the nuclear industry make the site an ideal location for a SMR.

At the proposed SMR location within the existing WNP-1 site, Construction Permit CPPR-134 was issued by the Nuclear Regulatory Commission (NRC) to authorize the construction of Nuclear Project No. 1 (WNP-1) on December 23, 1975. The project was subsumed on November 27, 1985. The civil-structural status at the time of construction termination was reported at 94% complete. The concrete and structural steel was near completion, reportedly at 99% complete. The age of the WNP-1 facilities is in the range of 19 to 29 years with an estimated nominal age of the civil structures being approximately 25 years. Efforts to decommission the site and raze portions of it to final grade are currently underway. URS concludes that, given the site's environmental conditions, the existing facilities will be adequate to support a SMR operation over a 60-year life span.

WNP-4 was less developed in 1985 with the structures being approximately 45% complete. The intake structure and piping was common between Units 1 and 4. The onsite structures, containment, safety related support structure, and turbine have been razed with some structural aspects abandoned in place.

This Study Report focuses on the assessment of adequacy of the existing WNP-1 facilities – some of which are essentially completed, and on the determination of what cost advantages could be realized for construction and operation of a SMR at that site.

2. Structural Adequacy

2.1 Scope

Perform a visual assessment of remaining structures at the Washington Nuclear Plant Units 1 (WNP-1) and 4 (WNP-4) sites and determine their structural adequacy to be repurposed in support of a Small Modular Reactor (SMR).

2.2 Objective

SMRs typically consist of a structure that is embedded 60 to 100 feet below ground surface with a small footprint, low elevation support structure above ground. The embedded part of the structure provides the "containment" function and supports the SMR in a basically passive state. Most ancillary Structures, Systems, and Components (SSCs) outside the SMR standard design are non-safety related.

The objective of the structural adequacy survey was to perform an onsite assessment of the existing structures at the abandoned sites that could be repurposed for reducing the overall cost of siting a SMR. This assessment specifically addresses the visual inspection of structures to determine their structural condition and the potential adverse effects due to aging.

2.3 Site Visit

The WNP-1 and WNP-4 sites within the Hanford Reservation in the State of Washington were visited on May 12, 2014. A layout plan of the Industrial Complex is provided as Plate 1 of Attachment 1. The WNP-1 site was judged to have the greatest potential of cost reductions for a SMR therefore the site assessment was concentrated in the WNP-1 area.

The Civil-Structural aspects of the WNP-1 site were substantially completed at the construction termination including the major structures, condensate water tank, buried raceways/conduit/piping, common intake structure, common circulating water systems and components, safety related spray pond (ultimate heat sink), grounding grid, support warehouses and office space. The site was evaluated for undeveloped areas within the Unit 2 exclusion zone that were in close proximity to the ancillary structures. This proximity to Unit 2 allows for the potential use of existing security and emergency response infrastructure. Some 40-100 acres in a concise location was identified as the primary target area, in close proximity to the WNP-1 structures.

The WNP-4 site was not substantially completed at the time construction was terminated and there are few ancillary support structures at the site. The site WNP-4 has been mostly razed to grade; parts of the containment, safety related support structure and turbine pedestal have been abandoned in place. Only a cursory review was performed for this site. Its potential to aid a SMR cost reduction is considered minimal.

The results of the site survey are summarized in the sections that follow.

2.3.1 General Site Conditions

Groundwater and soils conditions within the WNP-1 exclusion area are described below.

- Groundwater

The WNP-1 reference ground elevation is 455 feet and the Columbia River water level varies during the course of the year. The nominal groundwater elevation is 355 feet. The foundation of the reactor building is set at elevation 375 feet and the site was principally maintained dry during construction using un-watering techniques, e.g., surface sumps, sump pumps in vertical piping, etc. The presence of a low groundwater table is also supported by the visual inspection of the Make-Up Water Intake Structure. This structure is adjacent to the Columbia River. The pump pit at the lowest elevation in the structure was dry without evidence of historic seepage/leakage.

Groundwater in-leakage is typically a major source of deterioration which increases maintenance cost of below grade structures. The absence of long term groundwater interaction with below grade structures significantly decreases the potential of deterioration of concrete structures and its associated maintenance cost. It also reduces the potential of a defect that may not be visibly identified by an inspection from inside the structure. In summary, a low groundwater table decreases initial construction cost and long term maintenance.

- Soils

As reported in the WNP-2 Final Safety Analysis Report[1] – because of their proximity WNP-2 conditions are considered applicable to WNP-1 – the site is underlain by dense granular soils to at least a depth of 250 feet, which corresponds to the depth of the deepest boring. The entire site is mantled with a 2 to 3-foot layer of fine, eolian sand. This thin blanket is immediately underlain by about a 100-foot thick deposit of fine to coarse sand, which varies in consistency from slightly gravelly to that of a sand and gravel mixture. In the upper 40 feet, these sands increase in density with depth from medium dense to very dense. Below a depth of about 40 feet, all soils were found to be very dense. Below an average depth of 107 feet, borings encountered the extremely dense Ringold conglomerates (sand-gravel mixtures), which are underlain at about 217 feet by the lower unit of the Ringold Formation consisting primarily of very dense or hard, interbedded sand, silt, clay, and gravel. The water table was measured to be at an average depth of 62 feet and the estimated top of basalt bedrock is approximately 420 feet below the ground surface as determined by geophysical methods.

Because of the dense nature of the foundation soils, there is no possibility for the occurrence of soil liquefaction beneath major structures. This study concludes that the soil conditions at the site are appropriate for the installation of a SMR.

2.3.2 Make-Up Water Intake Structure

The intake structure is an embedded, conventionally reinforced concrete structure on the west bank of the Columbia River. The pumps and the makeup water piping are located one floor below grade. The MCCs are located at grade and are enclosed by a conventional steel frame and metal siding structure. The MCCs, pumps and piping showed no indication of corrosion or corrosion activity. The concrete structure did not reveal any structural cracks. The pump pit bottom is below river water level. The pit was dry with no physical evidence of water in-leakage or structural defects. The physical condition of the structure is considered in very good order with no visual defects.

2.3.3 Circulating Water Pump House (CWPH)

The CWPH is near the cooling towers and at the terminal end of the piping from the Make-Up Water Intake Structure and the cooling towers. The structure is a heavy industrial structure with Reinforced Concrete floors, basement type walls for the below grade areas. The above grade structure is structural steel with sheet metal siding. A light weight gantry crane is present for the purpose of servicing the pumps and piping. The cable trays and conduit at grade have been partially removed as part of the decommissioning process.

[1] http://pbadupws.nrc.gov/docs/ML1401/ML14010A294.pdf

There is no evidence of groundwater intrusion or staining in the below grade areas and no evidence of structural cracking in the concrete. The steel surfaces including the pipe, hand rails, structural steel were in good condition with no evidence of structural deterioration due to corrosion. It is feasible that the structure could be used for maintenance activities or repurposed for use with a SMR if determined economically feasible.

2.3.4 Spray Pond (Ultimate Heat Sink)

The WNP-1 spray pond is a concrete structure consisting of four walls and concrete bottom but is open to atmosphere at the top. Spray headers span the width of the spray pond, these consist of piping with elevated spay nozzles close to ground level. No structural defects were noted in the structural concrete. The piping and hand rails were still coated. Light oxidation was noted on the exposed end of the anchor bolts that could be probably attributed to scratching the bolt's galvanized surface when the anchor bolt was set. No appreciable corrosion was identified and no structural deterioration of the bolts was identified. The hand rails appeared to have one or two coating layers over a red primer. On the windward side of the handrails the protective coating has degraded but the primer layer was still intact. The coating was still present on the leeward side of the rail. The spray header piping exits a riser approximately 30 inches above the grade elevation. A mastic (e.g., bitumen based) caulk is evident between the pipe and the riser. The caulk is still present but some shrinkage has occurred with only a small gap adjacent to the spray piping being present in some areas. This is a non-structural observation. However, these observations are provided as evidence of a non-aggressive climate and the lack of environmental "attack" on the site structures considering that work was stopped in 1982 (22 years). If the spray pond were to be placed into service new sealant at construction joints should be anticipated.

2.3.5 Condensate Water Storage Tank

The safety related condensate storage tank has been removed from the site. The water tank was a typical 48± foot diameter tank located north-east of the containment equipment hatch. The foundation is abandoned in-place and could be repurposed if an equivalent or smaller tank is required and if the proposed SMR is acceptably sited.

2.3.6 Safety Related Structures (External Inspection)

The safety related General Services Building and Containment have been salvaged as part of the economic recovery effort at the site and items such as cable, stainless, feedwater heaters, major vessels have been removed. The interior of these structures was not assessed. The exterior of the structures did not reveal any structural defect which is consistent with other site observations.

As of the time of this study, none of the Safety Related structures are planned for use by the SMR.

2.3.7 Exterior of Cooling Towers (External Inspection)

Cooling tower concrete structures remain and their condition is consistent with other observations made at the site. Some components have been previously salvaged, the technology is dated, and the units may not be properly sized for SMR application. It is feasible that the structures can be repurposed but a detailed inspection should be performed once a specific technology has been identified.

As of the time of this study the existing cooling tower structures are not considered for use by a SMR.

3. Cost Estimate

3.1 Scope

The assessment of structural adequacy (Section 2) has shown that major infrastructure and several key structures (e.g., the Make-Up Water Intake Structure) are capable of supporting the installation of a Small Modular Reactor at the WNP-1 site.[2]

The scope of the cost estimate is to preliminarily assess the level of effort required to refurbish the existing WNP-1 infrastructure and available structures for possible SMR use. The study was constrained by the limited availability of information from the original Environmental Report and Safety Analysis Report for WNP-1. Hence, the cost estimate does not include potential savings from the utilization of environmental and design data from the original WNP-1 construction and operating license applications to the U.S. NRC. Without additional information a conservative approach is taken to not consider savings for licensing and permitting for the installation of a SMR at the WNP-1 site.

3.2 Methodology

The cost estimate is based on the Energy Economic Data Base (EEDB). A brief description of the data base and how it was used is described below.

3.2.1 Description of the Energy Economic Data Base

The Energy Economic Data Base[3] was developed by Raytheon Engineers & Constructors (a URS legacy company) to provide current, representative and consistent power plant technical and cost information to the U.S. Department of Energy (DOE). The database was first assembled in 1978 and has been updated regularly for DOE from 1978 through 1990[4]. Since 1991 URS has maintained the data base on a private basis, since DOE discontinued funding at that time. The purpose of the updates has been to reflect the impact of changing regulations and technology on the costs of electric power generating stations.

The EEDB updates incorporated costs for current regulatory requirements (not including potential Fukushima related upgrades), design, construction and management practices, labor productivity, and labor/material. Costs are developed as direct and indirect base construction costs. Direct costs are the costs of plant bulk commodities, equipment and their installation labor. Indirect costs are the costs of construction services, engineering, construction management, field supervision, startup and testing. Contingency, owner's costs and other information related costs are not included.

In the EEDB, base construction costs are in constant dollars and contain no arbitrary factors, such as contingency or escalation. Capital costs are the sum of the base construction costs and a number of other factors, such as owner's costs, contingency, escalation and allowance for funds used during construction. Users of the data base may apply these factors to the base construction costs to develop capital costs that suit their unique scenarios.

There are two types of estimates in the EEDB: Detailed and Summary. Detailed cost estimates are based upon a technical data model for over 50 major structure/systems and up to 400 subsystems. Each detailed technical data model includes system design descriptions, engineering drawings, milestone schedules and a detailed equipment list. The equipment list contains up to 1250 mini-specifications and up to 10,000 data

[2] We should note that adequacy of pump capacities was not examined in-depth because detailed data was not available for a proposed SMR and the WNP-1 pumps at the time of this study
[3] http://inis.iaea.org/search/search.aspx?orig_q=RN:16031682
[4] https://rsicc.ornl.gov/codes/psr/psr5/psr-531.html

lines of plant bulk commodities, equipment and labor hour quantities and costs. Summary cost estimates are based on abbreviated technical data models at the 50 major structure/systems level of detail or on available technical studies. The technical data models are based on actual current power plant designs and over 50 years of URS and legacy companies' power plant design and construction experience. Additionally, the data models have been periodically checked against actual field data to assure compatibility with current U.S. technical practice and cost experience.

Perhaps the most important attribute of the EEDB is the fact that assumptions and ground rules are clearly identified and are applied to all technical/cost updates. Site related factors are normalized by locating each technical data model on a common hypothetical "Middletown" site, for which there is a detailed geological and environmental description. Adjustments may be made to the technical/cost data models to reflect the characteristics of actual sites.

Each technical and cost data model is assembled and manipulated in accordance with a detailed and uniform code-of-accounts. Because of this code-of-accounts and the level of detail, ground rules, and periodic alignments with field data mentioned above, the users of the EEDB may have confidence that the data models are highly comparable, internally consistent and representative of current experience.

Because of the lack of detailed technical data for a potential SMR technology and for WNP-1 structures, systems and components, the Rough-Order-of-Magnitude (ROM) cost evaluation is limited to a determination of feasibility and is generally conservative.

3.2.2 Escalation Factors

To bring the costs reported in the EEDB to a January 2014 baseline, the estimate made use of escalation factors. These factors were obtained from Global Insight. This enterprise provides the most comprehensive economic, financial, and political coverage of countries, regions, and industries available from any source – covering over 200 countries and spanning more than approximately 170 industries – using a unique combination of expertise, models, data, and software within a common analytical framework to support planning and decision making.

Global Insight information was used for the following cost categories:

- Construction Average Hourly Earnings
- Ready-Mixed Concrete
- Lumber & Wood Products
- Plastic Construction Products
- Metals & Metal Products
- Fabricated Structural Metal Products
- Steel Power Boilers, Parts & Attachments
- Fabricated Pipe and Fittings
- Valves and Fittings
- Ferrous Foundry and Forge Shop Products
- Alloy Steel Forgings, except stainless and high-temperature
- Turbines & Turbine Generator Sets
- Power, Distribution, & Specialty Transformers
- Switchgear & Switchboard Apparatus
- Electrical Measuring & Testing Instruments

For each of these cost categories a weighted factor for labor, material and equipment was developed based on the cost distributions in the data base. Average escalation factors were then calculated.

Data from Global Insight has been used to calculate escalation factors for equipment, labor and materials from 1994 (the latest data that the model was revised) to 2011. From 2011 to 2014 a straight escalation rate of 2.3% per annum (an average for the Consumer Price Index) has been assumed.

3.2.3 Code of Accounts

The Code of Accounts used for the ROM cost estimate is based on the design of a 587 MWe Pressurized Water Reactor Nuclear Power Station (Refer to Attachment 2, EEDB COA Table). This model was selected because of the power rating, which is approximately the size projected for the SMR at Hanford.

Although the major components for the Nuclear Island and the Turbine Island for any proposed SMR will differ in design and fabrication from the unit described in the model, the ancillary components, such as make-up water facilities, yard fire protection components and waste water treatment will be very similar. Noting that many of the SSCs in the EEDB COA table are not applicable to SMRs, Section 3.3, below, provides an assessment of those accounts that can be credited (whether fully or partially) for use by a SMR at the WNP-1 site.

3.3 Items Identified for SMR Utilization

Based on the results of the brief site visit, which included interviews with Energy Northwest personnel, and utilizing the detailed descriptions provided in the EEDB, items were identified that could be utilized for SMR application. These are addressed below. Refer to Attachment 2 for a detailed description of each account.

3.3.1 Structures and Improvements

Refer to Attachment 3 for additional detail.

Yardwork

A significant amount of site preparation was executed during the construction of WNP-1. As a result a lot of credit can be taken for cut and fill, clearing and grubbing, grading, road and parking lot preparation, storm drains, outside lighting and other improvements. These improvements would be an asset for SMR siting at this location and have been partially credited.

Administration and Service Building

The site survey concluded that a SMR at the WNP-1 abandoned site could take advantage of the availability of building space already installed and operational that would be used as administrative and service facilities. Upgrades will be required and these are upgrades were considered in assigning a credited value to the existing facilities.

Fire Pump House

Interviews with Energy Northwest personnel conducted during the site visit of May 12, 2014 indicate that the Fire Pump House, Fire Water Main and Loop, and yard fire protection components are installed and operational. These would be fully available for SMR application and have been credited as such.

Technical Support Center

One of the advantages of siting a SMR at the WNP-1 location is the possibility of taking advantage of an existing Technical Support Center at the Hanford Reservation that could be used for the SMR. Some upgrades are assumed to be required in the cost calculation and are reflected in the amount of the credit.

Waste Water Treatment Building

A Waste Water Treatment facility is available that could be used to support SMR operations. This facility was constructed for the WNP-1 unit and should have sufficient capacity for the anticipated personnel load for the SMR. As a contingency some upgrades are projected in the cost estimate.

Security Building

As is the case with the Technical Support Center, the SMR could make use of existing facilities because of its location within the Hanford Nuclear Reservation. Some upgrades are conservatively estimated.

Waste Process Building

It was indicated during the site survey that a Waste Process Building was constructed for the WNP-1 unit. Furthermore, some facilities within Hanford could be used for SMR waste processing. However, this estimate has to conservatively assume that some upgrades and refurbishments will be needed.

3.3.2 Electric Plant Equipment

Station Service Equipment

Portions of the station service system have been installed at the site. These include a major transformer and feeders, and a distribution network. These would be available for use by the SMR.

Switchboards and Protective Equipment

Switchboards and Protective Equipment associated with the installed Service Equipment are credited in the cost estimate.

3.3.3 Miscellaneous Plant Equipment

Air, Water and Steam Service Systems

Air, Water and Steam Service Systems associated with the Fire Pump House and support equipment are partially credited in the cost estimate.

Communications Systems

Some communication systems, such as the Plant Address system and telephone service, are installed and available. In part because of WNP-1 construction, and in part for the proximity of existing facilities to the WNP-2 site which requires emergency notification. A credit is allocated for these systems.

Furnishings and Fixtures

Fixtures associated with offsite radiological, meteorological, water quality and seismic monitoring are installed and operational. A credit is also allocated for these fixtures.

Waste Water Treatment Equipment

Credit is given for a portion of Waste Water Treatment equipment located at the Waste Water Treatment building.

3.3.4 Main Condenser Heat Rejection System

Heat Rejection System Structures

The Make-Up Water Intake Structure is fully installed and in almost pristine condition. This structure could be fully utilized for the SMR.

Heat Rejection System Equipment

A portion of the Heat Rejection System equipment that is located at the intake structure and at other locations, including piping runs from the Columbia River to the site could be available for use by the SMR. Pump de-rating may be required and new piping and valves may need to be installed.

3.3.5 Construction Services

Temporary Construction Facilities

A significant advantage that the WNP-1 site represents for a SMR is the availability of facilities that could be used for construction. The construction of WNP-1 was very advanced prior to its suspension (see Section 2). As a result all of the construction infrastructure was in place and is still mostly operational, although some of the facilities may have to be repurposed from existing use. Existing construction facilities are a significant contributor to the overall credit reflected in the cost estimate.

Payroll, Insurance and Taxes

A portion of payroll and insurance costs, and taxes associated with the temporary construction facilities is also credited.

3.4 Estimated Cost of Items Identified

The EEDB 587 MWe PWR model was chosen as the most representative model for a potential SMR at the existing WNP-1 site. The detailed breakdown of costs at the three digit EEDB account level is presented in Attachment 3.

The EEDB model yields an overnight base construction cost of $1,836 million (2014$) for a 587 MWe PWR at a green site. With a 35% contingency[5], that is commensurate with a ROM (rough order of magnitude) estimate, the projected overnight base construction cost is approximately $2,479 million (2014$).[6,7] This

[5] Contingency is defined as a cost that is expected to be incurred but is not allocated to a specific account
[6] This compares favorably with other estimates, e.g., *SMR Financing and Economics*, Welling, C., Office of Nuclear Energy, U.S. Department of Energy. December 2010
[7] The EEDB estimates do not include post-Fukushima upgrades

cost excludes preliminary and detailed engineering, pre-construction licensing and permitting costs, interest during construction and some small miscellaneous direct costs, and Fukushima related upgrades.

The overall credits that can be conservatively allocated to the overnight construction cost for a SMR at the WNP-1 site amount to approximately $140 million in January 2014 dollars, as detailed below. See Attachment 3 for additional breakdown.

EEDB Account	Account Description	Credits (Jan 2014 $)
21	**STRUCTURES AND IMPROVEMENTS**	
211	Yardwork	17,732,864
218B	Administration and Service Building	3,251,552
218D	Fire Pump House	678,855
218L	Technical Support Center	1,027,697
218S	Waste Water Treatment Building	1,039,055
214	Security Building	1,672,057
216	Waste Process Building	11,657,794
24	**ELECTRICAL PLANT EQUIPMENT**	
242	Station Service Equipment	1,978,051
243	Switchboards	998,428
244	Protective Equipment	507,847
25	**MISCELLANEOUS PLANT EQUIPMENT**	
252	Air, Water and Steam Service Systems	10,361,378
253	Communications Systems	7,433,870
254	Furnishings and Fixtures	1,855,136
255	Waste Water Treatment Equipment	5,207,207
26	**MAIN CONDENSER HEAT REJECTION SYSTEM**	
261	Total Heat Rejection System Structures	1,476,022
262	Heat Rejection System Equipment	1,624,275
91	**CONSTRUCTION SERVICES**	
911	Temporary Construction Facilities	45,239,300
913	Payroll, Insurance and Taxes	26,404,747

4. Conclusions and Recommendations

4.1 Structural Adequacy

Existing structures at the WNP-1 site have withstood the impact of the elements and are in excellent condition. Groundwater, soil and seismic characteristics for the site are amenable for nuclear power plant construction and operation.

In general, it is feasible to utilize existing facilities to support SMR construction and operation over a 60-year life span. The utilization of these facilities would reduce the cost associated with the construction of the SMR.

4.2 Cost Savings

The cost savings projected using the EEDB model amount to approximately $140 million in January 2014 U.S. dollars. About 51% of these savings reflect the excellent condition and availability of site infrastructure, structures and facilities that could be used to support construction activities. The overall savings are close to 6% of the projected overnight construction cost for a new facility.

4.3 Recommendations

In view of these initial conclusions, and provided the cost of energy production for a SMR (by others) is found to be competitive within the region,[8] this study recommends that a more detailed analysis of costs be conducted to include specific technical and cost data from proposed SMRs and from the existing WNP-1 facilities. The specific technical data would provide a better basis for a final assessment.

[8] The development of the cost of energy production for a SMR at the WNP-1 site is being developed by other Contractors

Attachments

Attachment 1 – Supporting Documentation

Attachment 2 – Energy Economic Data Base (EEDB) Code of Accounts Descriptions

Attachment 3 – 587 MWe PWR Three-Digit Cost Summary

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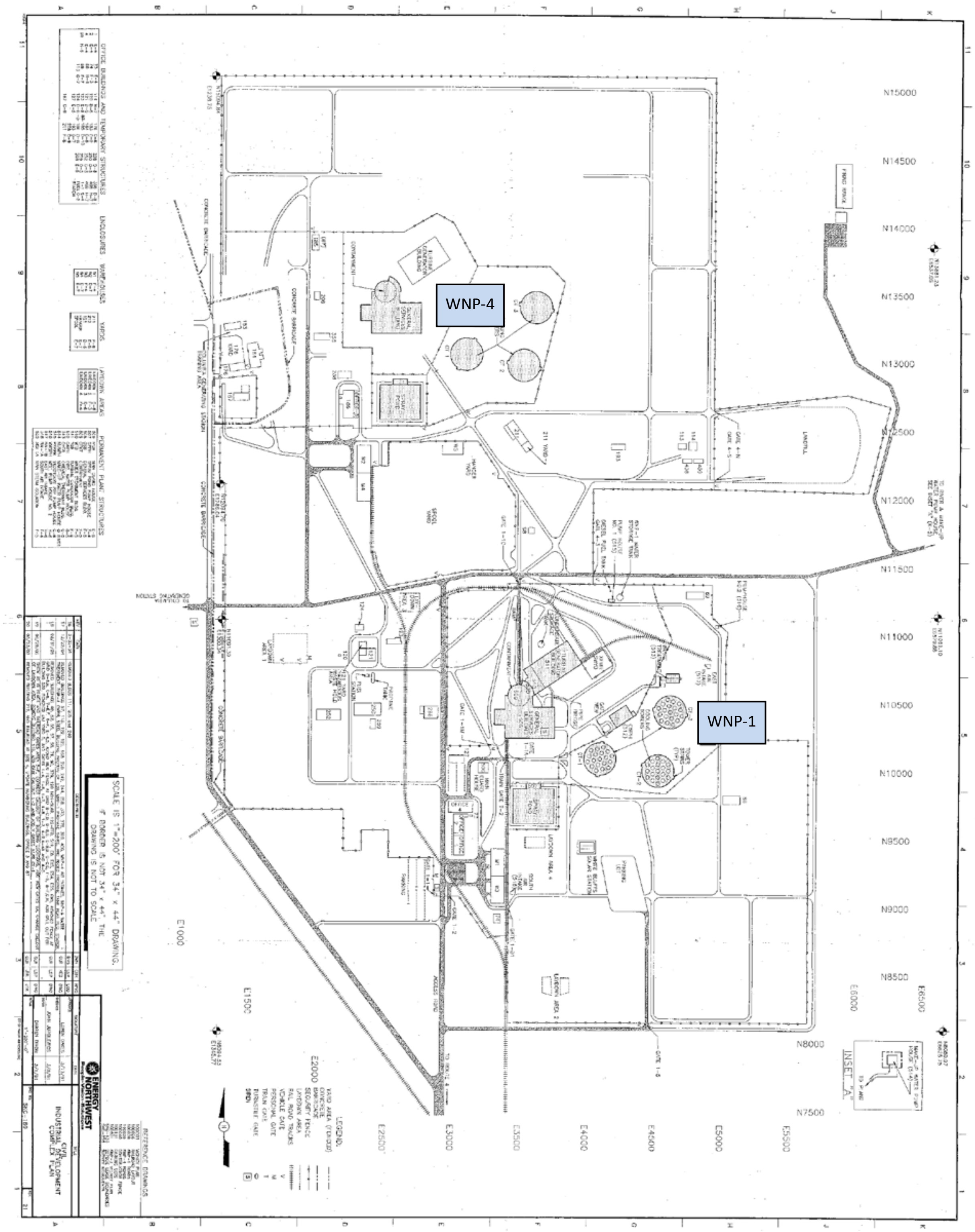
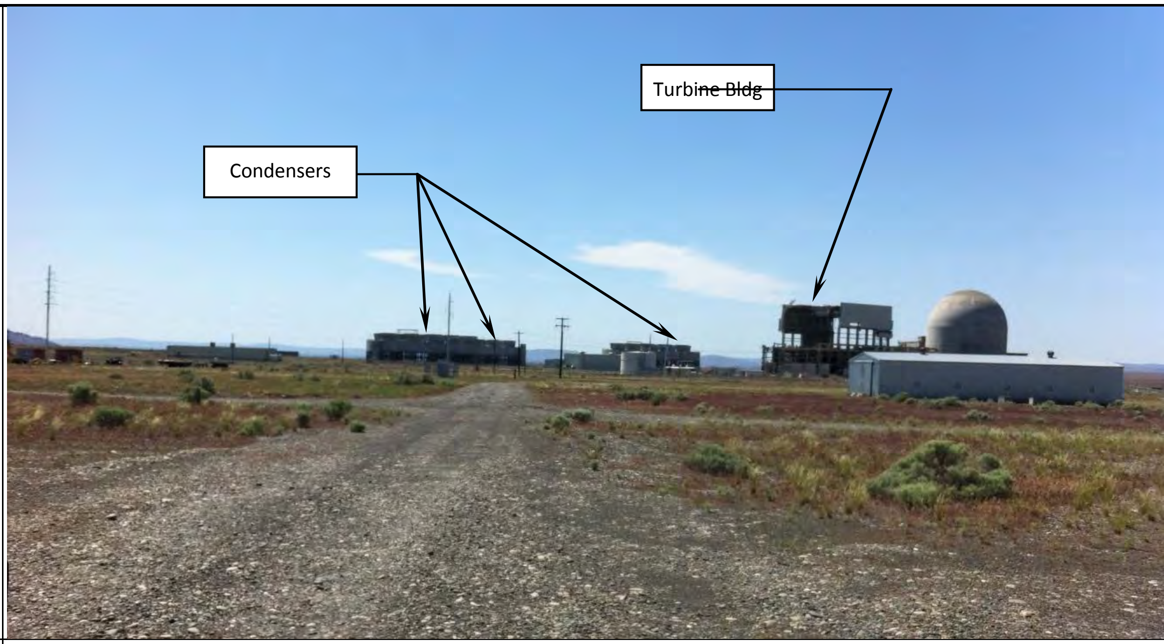
Attachment 1

SUPPORTING DOCUMENTATION



WNP-1 and WNP-4 Site Layout

Location: Hanford, WA Date: 05/12/2014 Orientation: Facing SW Location: N11750 E4500	
Description	WNP-1 Site. Over view of WNP-1. Turbine Building being dismantled, WNP-1 Water Tank in foreground center, and condensers CT-3/CT-2 are near center of photo and CT-1 is in the background. Site is arid and terrain is relatively flat.
Location: Hanford, WA Date: 05/12/2014 Orientation: Facing SE Location: N11750 E4500	
Description	WNP-1 Site. Structure Identified as Temporary Structure No. 69 which is located in the NE corner of the WNP-1 inclusion area. Offsite power shown in background. Site is relatively flat and level.

Location: Hanford, WA Date: 05/12/2014 Orientation: Facing North Location: Adjacent to Columbia River	
Description	Common WNP-1/WNP-4. Make Up Water Pump House. Above ground section is a simple steel frame structure with metal siding. Transformers at right of structure reportedly never been powered.
Location: Hanford, WA Date: 05/12/2014 Orientation: Facing North Location: Adjacent to Columbia River	
Description	WNP-1/WNP-4 Make Up Water Pump House interior near access door. WNP-1 MCCs in place. Empty location at north end of MCCs is the proposed location of the Unit 4 MCCs which were never installed. Embeds were located for use. Cable tray and conduit in-place. No structural cracks in floor.

<table>
<tr><td>Location:
Hanford, WA

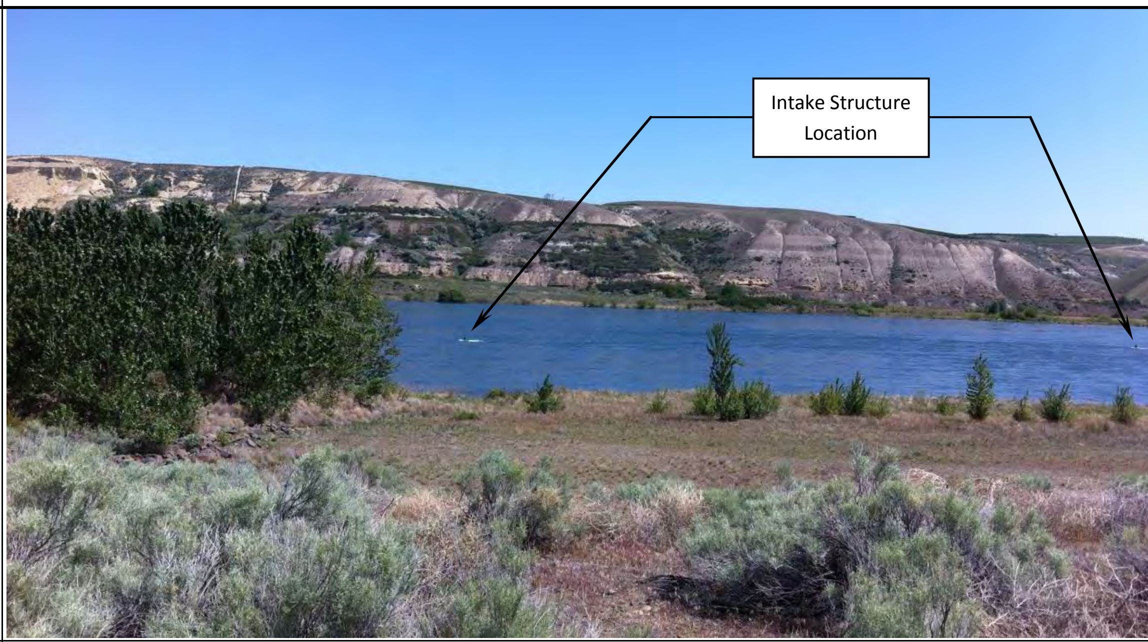
Date:
05/12/2014

Orientation:
Facing North

Location:
Adjacent to
Columbia River</td><td></td></tr>
<tr><td>Description</td><td>WNP-1/WNP-4 Make Up Water Pump House. Typical structural wall. No structural defects visually identified. Formwork location and bleed water staining from original construction remains visible to this date. Indication of a stable/preserving environment for structures.</td></tr>
<tr><td></td><td></td></tr>
<tr><td>Location:
Hanford, WA

Date:
05/12/2014

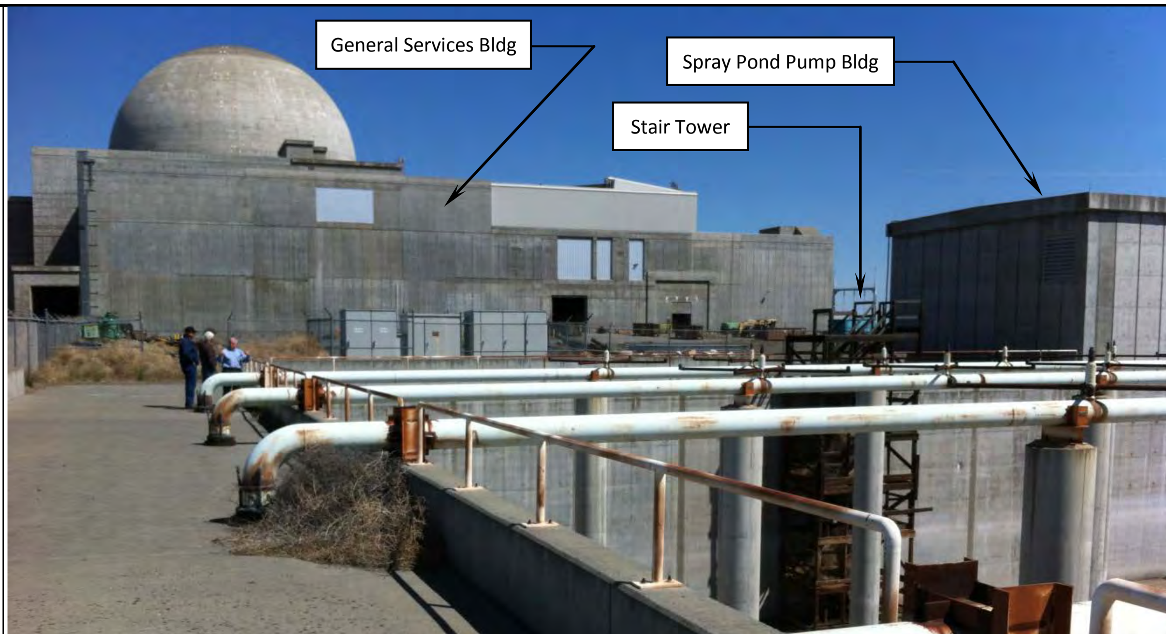
Orientation:
Facing East

Location:
Adjacent to
Columbia River</td><td>
</td></tr>
<tr><td>Description</td><td>WNP-1/WNP-4 Make Up Water Pump House. Columbia River. Turbulence (white capped area) near center of photo is the buoy marking the location of the intake structure. Second intake location is near the buoy at right edge of photo. Intake piping exits bottom of river at 90° with a screened entry structure.</td></tr>
</table>

<table>
<tr><td>Location:
Hanford, WA

Date:
05/12/2014

Orientation:
Facing East

Location:
N9600
E3450</td><td>
</td></tr>
<tr><td>Description</td><td>WNP-1 Site. Spray Pond. General Services Building and Containment in the background. Spray Pond Pump House (Bldg 507) located to the right. Steel frame is the stair tower providing access to Spray Pond Floor. Piping is spray headers.</td></tr>
<tr><td></td><td></td></tr>
<tr><td>Location:
Hanford, WA

Date:
05/12/2014

Orientation:
Facing SE

Location:
N9750
E3450</td><td></td></tr>
<tr><td>Description</td><td>WNP-1 Site. Spray Pond. Spray headers and column supports. Four Spray nozzles are located at each riser tap. Hand rail and piping were originally painted with a primer and single layer of coating. Outer coating has degraded on the windward side of pipe/hand rail and is typically steel present in other orientations. Primer still present in most areas (red tint in photo). Very little corrosion noted. Indication of stable environment.</td></tr>
</table>

ATTACHMENT 2 – CODE OF ACCOUNTS DESCRIPTIONS

This Code of Account is based on the design of a 587 MWe Pressurized Water Reactor Nuclear Power Station.

Account	Title of Account
21	Structures and Improvements
22	Reactor Plant Equipment
23	Turbine Plant Equipment
24	Electric Plant Equipment
25	Miscellaneous Plant Equipment
26	Main Condenser Heat Rejection System

ACCOUNT 21 – STRUCTURES AND IMPROVEMENTS

IMPROVEMENTS

Yardwork (Account 211)

Site preparation consists of clearing, grubbing, and stripping of top soil for all structures, roads, railroads, parking areas, materials handling areas and construction facilities. Rough grading quantities include the general cut and fill for the main plant structures and fine grading with landscaping.

Earth excavation, rock excavation, backfill, concrete fill and dewatering for the main plant structures are included with the structure associated yardwork. Excavation work for structures that are not included within the main excavation are included with the structural work for each of the individual buildings. The cut and fill work also includes hauling, dumping, stockpiling, placing and compacting.

Structural and fill concrete are produced by an on-site concrete batch plant. Excavated material is used on site for general fill whenever possible. Spoil areas and storage areas are utilized for excavated material not used for fill or for top soil. Erosion and sedimentation control of those areas is practiced in accordance with EPA requirements. Temporary settling basins are provided to collect all runoff during construction prior to discharge.

The transformer area, above ground oil storage tanks and other oil or chemical storage and handling areas are designed to contain spills and collect surface water runoff. This runoff, together with the turbine building floor drains and other plant dirty drains, is routed by underground piping to the holding pond or to the waste water treatment building for treatment, as required, before discharge.

The yard drainage system consists of interceptor ditches (paved and unpaved) and storm drains with catch basins to carry off storm water from developed areas. Water courses that are intercepted near the plant are diverted by ditches into existing stream beds or storm drains. Culverts carry stream flow under the railroad and roads. The yard surface water drainage is discharged via the existing water courses wherever possible. Building roof drainage is directed to the yard drainage system.

The sanitary sewage system, piping and toilet facilities for permanent plant requirements are provided based on 35 gallons per day per person and a permanent daily work force of 290 people, for a treatment rate of 10,150 gallons per day. This system is a package type activated sludge sewage treatment plant, including final chlorination, to meet secondary treatment effluent standards.

Highway access is provided to the site by five miles of secondary roads connecting to a state highway. These roads are in good condition and need no additional improvements. An on-site asphalt road, paved in accordance with the standard thicknesses for public highways, is provided around the main plant structures. Service roads are arranged to provide access to truck sized doors in the plant and to all buildings requiring servicing or maintenance by vehicles. In addition, parking areas, concrete curbs and walks are provided. Temporary construction roads with minimum thickness paving and unpaved roads for materials handling equipment are provided.

Railroad access to the site is provided by constructing a single track rail- road spur which intersects the main Railroad. The length of the spur from the main line to the plant site is five miles. In addition fencing, a main gate guard house, and roadway and yard lighting are provided with the yardwork.

STRUCTURES

The primary structure in the plant is the reactor building which is Seismic Category 1. The reactor building houses the reactor and its associated coolant system, provides biological shielding, and prevents significant release of radiation to the environment in case of abnormal events in the reactor coolant system. The interior concrete of the reactor containment supports the reactor plant components and equipment.

The reactor building and other Seismic Category 1 structures house all safety- related equipment essential for safe plant operation, shut-down and control. Construction of these structures generally includes a reinforced concrete foundation mat, exterior walls, interior walls, floor slabs and roof slabs. The exterior walls are designed to resist horizontal loads and behave as shear walls. The interior slabs and roof slabs are supported on heavy structural steel framing.

Non-Seismic Category 1 structures house equipment and components not required for plant safety or safe shut-down. In general, these structures consist of structural steel framing, metal siding and concrete channel plank roof deck. They bear on reinforced concrete spread footings or reinforced concrete footings founded on the rock underlying the site. The Non-Seismic Category 1 structures are designed and located such that their failure will not cause loss of function of a Seismic Category 1 structure.

Interconnecting piping systems are provided for building service systems such as HVAC, rainwater conductor and sewage systems. They comprise the piping, fittings, valves, hangers and supports, and other components required for a complete system. Materials and wall thicknesses are chosen based on the service conditions and operational requirements of each system. The factors generally considered include: temperature, pressure, corrosion resistance, abrasion resistance, fluid purity requirements and cost. Carbon steel is used for steam (below 750°F), clean water, air, oil, and other services without special requirements. Other materials used include cast iron for sanitary drains and some below grade service, copper for potable water, galvanized steel for yard drains, and polyvinyl chloride (PVC) and fiberglass reinforced plastic (FRP) for corrosive services.

Reactor Building (Account 212) − Houses the Nuclear Steam Supply System (NSSS)and its associated coolant system, provides biological shielding and prevents significant release of radiation in case of abnormal events in the reactor coolant system. The interior concrete of the reactor containment supports the reactor plant components and equipment, provides biological shielding and protects the steel containment from postulated pipe break effects in the reactor coolant system.

Turbine Room and Heater Bay (Account 213) − Houses the turbine-generator, condensers and associated equipment, feedwater heaters, feedwater pumps, condensate pumps, condensate polishing and demineralizing equipment, other auxiliary equipment, and electrical switchgear rooms.

Security Building (Account 214) − Provides a controlled means of access to the plant and houses the center for monitoring and controlling access to selected critical areas within the plant.

Auxiliary Building and Tunnels (Account 215) − Houses auxiliary nuclear equipment, the fuel storage area, the waste process area, the main control room and associated facilities, the emergency diesel-generator units, the diesel engine fuel oil storage tanks, and the emergency feedwater pumps. The waste process area includes equipment for gaseous, liquid and solid radioactive waste processing and boron recovery. The control room area houses the necessary instrumentation and control equipment essential for plant operation under normal and abnormal conditions.

Control Room and Diesel Generator Area (218A) – Houses the Main Control Room and the emergency diesel generators.

Administration and Service Building (Account 218B) – Houses the general offices, conference rooms, storage areas, auxiliary boilers, water treatment equipment and various laboratories and shops.

Fire Pump House (Account 218D) – The fire pump house encloses switchgear, the fire pumps and the pumps and heat exchanger sets used for freeze protection of the storage tanks. Each fire protection tank foundation is of reinforced concrete.

Emergency Pump House Building (Account 218E)

Manway Tunnels (Account 218F) – These are personnel access tunnels within the Radioactive Control Area

Electrical Tunnels (Account 218 G) – These tunnels provide protection for electrical runs between buildings.

Non-Essential Switchgear Building (Account 218H) – Houses most of the non-safety-related electrical switchgear and load centers.

Main Steam and Feedwater Pipe Enclosure (Account 218J) – Houses the Seismic Category 1 sections of the main steam and feedwater piping external to the reactor building.

Pipe Tunnels (Account 218K) – The pipe tunnels are water-sealed reinforced concrete box type structures that provide protection for piping runs between various buildings.

Technical Support Center (Account 218L) – Houses the necessary monitoring, control and communication equipment required for on-site response to emergency conditions.

Containment Equipment Hatch Missile Shield (Account 218P) – The missile shield provides an entrance enclosure and protects the steel equipment hatch from tornado generated missiles.

Waste Water Treatment Building (Account 218S) – The building houses a control area, storage area, pumps, tanks and other waste water treatment equipment. Large items, such as the batch holding tank, would be located adjacent to the building.

Ultimate Heat Sink Structure (Account 218T) – Houses the cooling towers associated equipment necessary to provide emergency service water to plant.

Control Room Emergency Air Intake Structures (Account 218V) – Each air intake structure is capable of providing air required to ensure habitability of the control room for abnormal occurrences during plant operation. The structures contain radiation monitors and other equipment.

ACCOUNT 22 – REACTOR PLANT EQUIPMENT

The reactor plant equipment produces and supplies saturated steam to the turbine-generator unit, which converts the thermal energy to electric energy. The NSSS includes the reactor pressure vessel and internals, control rod system, reactor core cooling system, pressurizing system, residual heat removal system, safety injection system, containment spray system, combustible gas control system, radioactive waste system, chemical and volume control system, fuel handling and storage system, and associated instrumentation and controls for these systems.

The Balance of Reactor Plant (BORP) systems include the inert gas system, reactor water make-up system, coolant treatment and recycle system, fluid leak detection system, nuclear service water system, primary component cooling water system, and associated instrumentation and control for these systems.

Interconnecting piping systems are included with each NSSS and balance of reactor plant auxiliary system. They comprise the piping, fittings, valves, containment piping penetrations, steam traps, strainers, specialties, hangers and supports, pipe whip and seismic restraints, insulation and other components required for a complete system. Materials and wall thicknesses are chosen based on the service conditions and operational requirements of each system.

The reactor plant equipment account includes:

<u>Account 221</u> Reactor Equipment (reactor vessel, reactor core, rod cluster control assemblies, and control rod drive mechanisms)

<u>Account 222</u> Main Heat Transfer and Transport System (reactor coolant pumps, steam generators, primary piping, pressurizer, pressurizer relief tank, and safety and relief valves)

<u>Account 223</u> Safeguards System (residual heat removal system, safety injection system, containment spray system, and combustible gas control system)

<u>Account 224</u> Radwaste Processing System (liquid waste, steam generator blowdown processing, gas waste and solid waste systems)

<u>Account 225</u> Fuel Handling and Storage System (new fuel storage, spent fuel storage, new and spent fuel handling, and spent fuel pool cooling and purification equipment and systems)

<u>Account 226</u> Other Reactor Plant Equipment (H2/N2 gas supply system, reactor make-up water system, chemical and volume control system, boron recycle system, fluid leak detection system, nuclear service water system, primary component cooling water system, maintenance equipment and sampling system)

<u>Account 227</u> Reactor Plant Instrumentation and Control (bench-board, panels and racks, process computer, monitoring systems, plant control systems and associated instruments)

ACCOUNT 23 – TURBINE PLANT EQUIPMENT

The turbine plant equipment includes the steam handling, power conversion and condensate/feedwater machinery of the steam cycle. All turbine plant equipment includes margin in the design to compensate for some wear and performance degradation during the life of the plant.

The thermal energy from the reactor primary coolant loop generates saturated steam within the steam generators. The main steam piping supplies this steam to the throttle/control valves of the turbine-generator unit and to the inlet of the moisture separator/reheaters.

The majority of the main steam flow exhausts from the high pressure turbine and passes through the moisture separator/reheaters. The separator/reheaters remove water droplets and reheat the steam before it enters the two low pressure turbines. Condensate is pumped from the condenser hotwells through bed polishing demineralizers, the steam packing exhauster condenser and the feedwater heaters.

Interconnecting piping systems are included with each turbine plant auxiliary system. They comprise the piping, fittings, valves, steam traps, strainers, specialties, hangers and supports, insulation and other components required for a complete system. This account comprises the following:

Account 231	Turbine-Generator (turbomachinery, generator, exciter, stator cooling water system, gas systems, hydrogen seal oil system, electro-hydraulic control system, turbine gland steam sealing system, moisture separator/reheater, moisture separator/reheater drain system, lubricating oil system, turbine oil storage and conditioning system)
Account 232	Not used
Account 233	Condensing System (condensers, condensate system, condenser gas removal system, turbine bypass system and condensate polishing system)
Account 234	Feedheating System (feedwater heaters, feedwater system and extraction steam system)
Account 235	Other Turbine Plant Equipment (main vapor piping system, turbine building closed cooling water system, demineralized water make-up system, chemical treatment system and neutralization system)
Account 236	Turbine Plant Instrumentation and Control (turbine plant control board, panels, cabinets and racks, and process computer)

ACCOUNT 24 – ELECTRIC PLANT EQUIPMENT

The electric plant equipment conveys the electric power generated in the plant to the low voltage bushings of the generator step-up transformers (GSU), controls and meters the electric energy, and protects the components through which the power flows. It also conveys electric power from the electric generator, the off-site power system, or the emergency generators to the plant auxiliaries and the plant control, protection and surveillance systems during normal operation. And to the plant protection system and engineered safety features during normal operation, abnormal conditions, and accident conditions.

Continuous ratings of equipment conveying power from the main generator to the GSU are based on valves wide open turbine operation and generator voltage variation of plus or minus five percent.

Continuous ratings of equipment serving plant auxiliaries and systems, as well as interrupting ratings of their protective and disconnecting devices, are based on equipment load tabulations, fault studies and voltage regulation studies. Equipment continuous current ratings are based on the maximum continuous load plus the largest spare auxiliary, and the effects of diversity. Short time intermittent loads are not included. The following accounts are included:

Account 241 — Switchgear (generator load break switch and station service switchgear)

Account 242 — Station Service Equipment (station service and start-up transformers, unit substations and auxiliary power sources)

Account 243 — Switchboards (control boards and panels and auxiliary power and signal boards)

Account 244 — Protective Equipment (general station grounding, lightning protection, cathodic protection, and heat tracing and freeze protection systems)

Account 245 — Electric Structures and Wiring Containers (underground duct runs and conduit and cable tray raceways)

Account 246 — Power and Control Wiring (main generator bus duct, power wiring, control cable and instrument wire, and containment penetrations)

ACCOUNT 25 – MISCELLANEOUS PLANT EQUIPMENT

Miscellaneous plant equipment includes systems and components for maintenance, plant start-up, or general supply of plant equipment requirements. Included are the cranes and hoists; air, water and steam services; auxiliary boiler and associated equipment; plant fuel oil system; fire protection system; communications systems; and various on-site and off-site environmental monitoring systems.

Interconnecting piping systems are included with each system, as required. They comprise the piping, fittings, valves, steam traps, strainers, specialties, hangers and supports, insulation, and other components required for a complete system.

The following paragraphs outline the equipment included.

Account 251 — Transportation and Lifting Equipment (major cranes and other cranes and hoists)

Account 252 — Air, Water and Steam Service Systems (compressed air systems, service water system, fire protection system, potable water system, auxiliary steam system and plant fuel oil storage tank)

Account 253 — Communications Systems (local communications system, fire detection system and security system)

Account 254 — Furnishings and Fixtures (instrument shop apparatus, off-site radiological monitoring system, meteorological monitoring system, water quality monitoring system, seismic monitoring system and other furnishings and fixtures)

Account 255 — Waste Water Treatment Equipment

ACCOUNT 26 – MAIN CONDENSER HEAT REJECTION SYSTEM

The main condenser heat rejection system is a closed loop circulating water system. It consists of buildings, structures and mechanical equipment that serve the main condensers and service water system to reject the plant excess heat through one natural draft wet evaporative cooling tower. The circulating water is chlorinated to control biological fouling.

Make-up water from a nearby water body initially passes through a bar rack to remove any large debris. It then passes through traveling water screens to protect the pumps. Automatic self-cleaning strainers following the pumps further remove suspended material. After straining, most of the make-up water is discharged to the cooling tower basin to replace water lost by evaporation and blowdown. Sulfuric acid is injected into the cooling tower make-up water as required to avoid scaling. The remaining make-up water is clarified and demineralized for use as steam cycle make-up.

Interconnecting piping systems are included with the auxiliary systems. They comprise the piping, fittings, valves, hangers and supports, and other components required for a complete system. This account includes:.

Account 261	Structures (make-up water intake structure, circulating water pump house and make-up water pretreatment building)
Account 262	Mechanical Equipment (circulating water pumps, cooling towers and cooling tower basins, plant make-up and blowdown equipment and make-up water pretreatment plant)

EEDB ACCOUNT	ACCOUNT DESCRIPTION	JANUARY 2014 $ FACTORY COST	LABOR COST	MATERIAL COST	TOTAL COST	CREDITS
21	**STRUCTURES AND IMPROVEMENTS**					
211	YARDWORK	$ 569,717	$ 20,137,969	$ 15,079,846	$ 35,787,532	$ 17,732,864
218A	CONTROL ROOM/DIESEL GENERATOR BUILDING	$ 2,087,842	$ 17,436,546	$ 9,413,341	$ 28,937,730	$ -
218B	ADMINISTRATION AND SERVICE BUILDING	$ 1,183,697	$ 5,343,310	$ 4,311,502	$ 10,838,510	$ 3,251,552
218D	FIRE PUMP HOUSE	$ 56,720	$ 361,765	$ 260,371	$ 678,855	$ 678,855
218E	EMERGENCY PUMPHOUSE BUILDING	$ 49,298	$ 2,686,166	$ 1,319,918	$ 4,055,383	$ -
218F	MANWAY TUNNELS (RCA)	$ -	$ 838,255	$ 377,287	$ 1,215,541	$ -
218G	ELECTRICAL TUNNELS	$ 13,577	$ 91,989	$ 33,176	$ 138,743	$ -
218H	NON-ESSENTIAL SWITCHGEAR BUILDING	$ 30,343	$ 452,149	$ 406,742	$ 889,233	$ -
218J	MAIN STEAM AND FEEDWATER PIPE ENCLOSURE	$ 45,777	$ 8,258,865	$ 4,387,225	$ 12,691,869	$ -
218K	PIPE TUNNELS	$ -	$ 310,566	$ 187,906	$ 498,472	$ -
218L	TECHNICAL SUPPORT CENTER	$ 78,279	$ 722,627	$ 408,149	$ 1,209,055	$ 1,027,697
218P	CONTAINMENT EQUIPMENT HATCH MISSILE SHIELD	$ -	$ 253,471	$ 86,909	$ 340,380	$ -
218S	WASTEWATER TREATMENT BUILDING	$ 12,524	$ 682,783	$ 459,199	$ 1,154,506	$ 1,039,055
218T	ULTIMATE HEAT SINK STRUCTURE	$ 65,958	$ 4,699,955	$ 2,320,415	$ 7,086,327	$ -
218V	CONTROL ROOM EMERGENCY AIR INTAKE	$ -	$ 93,223	$ 48,717	$ 141,940	$ -
212	REACTOR BUILDING	$ 21,475,306	$ 58,829,427	$ 25,904,403	$ 106,209,136	$ -
213	TURBINE ROOM AND HEATER BAY	$ 919,769	$ 17,665,601	$ 20,084,672	$ 38,670,042	$ -
214	SECURITY BUILDING	$ 78,279	$ 1,395,378	$ 616,414	$ 2,090,072	$ 1,672,057
215	AUXILIARY BUILDING	$ 4,657,155	$ 16,392,001	$ 8,239,318	$ 29,288,475	$ -
216	WASTE PROCESS BUILDING	$ 982,687	$ 14,244,375	$ 8,088,526	$ 23,315,589	$ 11,657,794
217	SPENT FUEL STORAGE AREA	$ 1,519,817	$ 7,287,355	$ 7,880,141	$ 16,687,313	$ -
22	**REACTOR PLANT EQUIPMENT**					
221	REACTOR EQUIPMENT	$ 285,469,860	$ 6,629,724	$ 10,257,428	$ 302,357,012	$ -
222	MAIN STEAM TRANSFER AND TRANSPORT SYSTEM	$ 4,321,111	$ 9,251,171	$ 953,836	$ 14,526,118	$ -
223	SAFEGUARDS SYSTEM	$ 8,503,963	$ 7,699,255	$ 968,918	$ 17,172,135	$ -
224	RADWASTE PROCESSING SYSTEM	$ 21,701,701	$ 5,561,022	$ 1,098,416	$ 28,361,139	$ -
225	FUEL HANDLING AND STORAGE	$ 3,223,263	$ 1,240,888	$ 162,246	$ 4,626,397	$ -
226	OTHER REACTOR PLANT EQUIPMENT	$ 25,812,348	$ 23,223,073	$ 3,601,231	$ 52,636,652	$ -
227	REACTOR PLANT INSTRUMENTATION AND CONTROL	$ 27,366,609	$ 15,277,643	$ 3,788,049	$ 46,432,300	$ -
228	REACTOR BUILDING MISCELLANEOUS ITEMS	$ -	$ 6,718,870	$ 5,217,213	$ 11,936,083	$ -
23	**TURBINE PLANT EQUIPMENT**					
231	TURBINE-GENERATOR	$ 180,546,475	$ 10,993,160	$ 2,291,935	$ 193,831,572	$ -
233	CONDENSING SYSTEM	$ 28,089,188	$ 11,643,406	$ 1,683,595	$ 41,416,189	$ -
234	FEEDWATER HEATING	$ 22,759,627	$ 10,039,283	$ 999,345	$ 33,798,255	$ -
235	OTHER TURBINE PLANT EQUIPMENT	$ 15,218,440	$ 13,931,172	$ 1,688,997	$ 30,838,608	$ -
236	TURBINE PLANT INSTRUMENTATION AND CONTROL	$ 3,644,029	$ 8,700,084	$ 807,826	$ 13,151,939	$ -
237	TURBINE PLANT MISCELLANEOUS ITEMS	$ -	$ 7,214,575	$ 5,494,971	$ 12,709,546	$ -
24	**ELECTRIC PLANT EQUIPMENT**					
241	SWITCHGEAR	$ 20,750,837	$ 1,108,547	$ 178,430	$ 22,037,814	$ -
242	STATION SERVICE EQUIPMENT	$ 37,767,311	$ 2,890,425	$ 533,061	$ 41,190,796	$ 1,978,051
243	SWITCHBOARDS	$ 2,918,302	$ 646,463	$ 253,359	$ 3,818,125	$ 998,428
244	PROTECTIVE EQUIPMENT	$ -	$ 4,504,275	$ 3,879,494	$ 8,383,768	$ 507,847
245	ELECTRIC STRUCTURES AND WIRING CONTAINERS	$ -	$ 31,863,688	$ 9,025,894	$ 40,889,582	$ -
246	POWER AND CONTROL WIRIING	$ 3,125,336	$ 21,205,787	$ 16,398,333	$ 40,729,457	$ -
25	**MISCELLANEOUS PLANT EQUIPMENT**					
251	TRANSPORTATION AND LIFTING EQUIPMENT	$ 6,329,073	$ 1,312,162	$ 141,777	$ 7,783,011	$ -
252	AIR, WATER AND STEAM SERVICE SYSTEMS	$ 11,724,691	$ 21,853,090	$ 7,601,455	$ 41,179,236	$ 10,361,378
253	COMMUNICATIONS SYSTEMS	$ 3,221,894	$ 6,998,851	$ 1,123,926	$ 11,344,669	$ 7,433,870
254	FURNISHINGS AND FIXTURES	$ 3,992,504	$ 980,521	$ 132,046	$ 5,105,070	$ 1,855,136
255	WASTE WATER TREATMENT EQUIPMENT	$ 1,424,790	$ 3,660,934	$ 395,545	$ 5,481,271	$ 5,207,207
26	**MAIN CONDENSER HEAT REJECTION SYSTEM**					
261	TOTAL HEAT REJECTION SYSTEM STRUCTURES	$ 247,309	$ 3,806,833	$ 2,424,308	$ 6,478,450	$ 1,476,022
262	HEAT REJECTION SYSTEM EQUIPMENT	$ 39,758,576	$ 17,389,225	$ 2,199,782	$ 59,347,582	$ 1,624,275
	TOTAL DIRECT COSTS	**$ 791,743,982**	**$ 434,527,905**	**$ 193,215,593**	**$ 1,419,487,481**	**$ 68,502,089**
91	**CONSTRUCTION SERVICES**					
911	TEMPORARY CONSTRUCTION FACILITIES	$ -	$ 53,972,789	$ 15,626,134	$ 69,598,923	$ 45,239,300
912	CONSTRUCTION TOOLS & EQUIPMENT	$ 47,292,464	$ 15,967,282	$ 6,103,586	$ 69,363,332	$ -
913	PAYROLL, INSURANCE & TAXES	$ 52,809,495	$ -	$ -	$ 52,809,495	$ 26,404,747
914	PERMITS, INSURANCE & LOCAL TAXES	$ -	$ -	$ -	$ -	$ -
915	TRANSPORTATION	$ -	$ -	$ -	$ -	$ -
92	**ENGINEERING & H.O. SERVICES**					
921	HOME OFFICE SERVICES	$ -	$ 77,427,548	$ -	$ 77,427,548	$ -
922	HOME OFFICE Q/A	$ -	$ 2,945,527	$ -	$ 2,945,527	$ -
923	HOME OFFICE CONSTRUCTION MGMT	$ -	$ 10,233,536	$ -	$ 10,233,536	$ -
93	**FIELD OFFICE SERVICES**					
931	FIELD OFFICE SERVICES	$ -	$ -	$ 7,429,007	$ 7,429,007	$ -
932	FIELD JOB SUPERVISION	$ -	$ 97,961,542	$ -	$ 97,961,542	$ -
933	FIELD QA/QC	$ -	$ 18,165,893	$ -	$ 18,165,893	$ -
934	PLANT STARTUP & TEST	$ -	$ 10,996,177	$ -	$ 10,996,177	$ -
	TOTAL INDIRECT COSTS	**$ 100,101,959**	**$ 287,670,294**	**$ 29,158,727**	**$ 416,930,980**	**$ 71,644,048**
	BASE CONSTRUCTION COST				**$ 1,836,418,460**	**$ 140,146,137**
35%	**CONTINGENCY (not included in credits)**				**$ 642,746,461**	**$ -**
	BASE CONSTRUCTION COST + CONTINGENCY				**$ 2,479,164,921**	**$ 140,146,137**
	OWNER'S COST (not calculated)					

ESTIMATED COST SAVINGS FOR ONE YEAR SCHEDULE IMPROVEMENT OF AN SMR

Assumptions

- **Capital cost of 540 MWe SMR**
  - Nth of a kind plant: $2.5 billion
  - Additional first-of-a-kind costs used for this study: $1 billion
  - Total used for management savings calculation: $3.5 billion
  - Assumes $2.9 billion financed after DOE cost sharing (used for interest savings)
  - Reference: Dale Atkinson, PowerPoint presentation dated 2013, provided to the study team in April 2014
  - Reference: Electricity Generating Portfolios with Small Modular Reactors, Goeffrey Rothwell, Ph.D., Stanford University, Francesco Ganda. Ph.D., Argonne National Laboratory, dated May 2014, pp. 12 (listed in Appendix B)
- **SMR construction lead time: 34.7 months**
  - Value use for calculation: 36 months
  - Reference: Electricity Generating Portfolios with Small Modular Reactors, Goeffrey Rothwell, Ph.D., Stanford University, Francesco Ganda. Ph.D., Argonne National Laboratory, dated May 2014, pp. 14
- **Project management and administration cost (URS typical large first-of-a-kind projects):**
  - High range: 15%
  - Low range: 12%
- **Project duration incurring management costs: 7 years (conservative estimate based on Vogtle Plants 3 – 4 moderated by Argonne National Lab Estimates)**
  - Reference: Electricity Generating Portfolios with Small Modular Reactors, Goeffrey Rothwell, Ph.D., Stanford University, Francesco Ganda. Ph.D., Argonne National Laboratory, dated May 2014]
- **Cost of capital during construction**
  - Reference: Electricity Generating Portfolios with Small Modular Reactors, Goeffrey Rothwell, Ph.D., Stanford University, Francesco Ganda. Ph.D., Argonne National Laboratory, dated May 2014, pp. 5
  - Low range interest rate: 5% based on rate assumed for state-regulated utilities with Construction Work in Progress, CWIP, financing with access to loan guarantees and production tax credits
    - Resulting cost of capital: $138 million for $2.9 billion financed
      - Reference: Electricity Generating Portfolios with Small Modular Reactors, Goeffrey Rothwell, Ph.D., Stanford University, Francesco Ganda. Ph.D., Argonne National Laboratory, dated May 2014, pp. 22
  - High range interest rate: 7.5% based on rate assumed for state-regulated utilities with Allowance for Funds Used During Construction financing with access to loan guarantees and production tax credits
    - Resulting cost of capital: $208 million

- Reference: Electricity Generating Portfolios with Small Modular Reactors, Goeffrey Rothwell, Ph.D., Stanford University, Francesco Ganda. Ph.D., Argonne National Laboratory, dated May 2014, pp. 22

Calculation

- **Management and administration cost savings**
  - Total project management and administration cost over 7 years
    - @12% of $3.5 billion capital cost: $420 million
    - @15% of $3.5 billion capital cost: $525 million
  - One year schedule reduction = 14% of total management and administration cost resulting in savings
    - @15%: 78.7% (use $75 million)
    - @12%: 58.8% (use $60 million)

- **Interest savings**
  - Low range
    - Using 6 months (versus 1 year) of the mean annual cost of interest during construction period (50% of the actual schedule savings): 16.6% of $138 million = $22.9 million (use $20 million)
  - High range
    - Using 8 months (versus 1 year) of the mean annual cost of interest during construction period (66% of the actual schedule savings): 23% of $208 million = $47.8 million (use $40 million)

- **Total savings**
  - Management and administration: $75–100 million
  - Interest: $20–40 million
  - Combined: $60–115 million
  - Used for the SMR siting study: $80–110 million

CHARACTERIZATION AND LICENSING APPROACH AND COST SAVINGS AT WNP-1

1.6 Licensing and Regulatory Requirements/Regulatory Guidance Applicable to SMRs

The NRC develops standard review plans for their legislation for light water reactors (LWR) pursuant to existing regulations, NRC guidance document, and under requirements established in the NRC's NUREG-0800, "Standard Review Plan [SRP] for the Review of Safety Analysis Reports for Nuclear Power Plants" (NRC 2007). The NRC's current regulations have focused on larger- capacity light-water reactors.

The NRC has been undertaking formal correspondence and holding discussions with SMR vendors and the industry on policy issues such as security, emergency preparedness and control room staffing. The NRC anticipates receiving the first formal applications to review SMR designs by late 2014 and on into 2015.

The NRC's regulatory framework for SMRs is supported by the commission's advanced reactor research program, to help inform regulatory decision-making. Nine key areas of research have been identified, with priorities including the general framework and how to arrive at the regulatory stipulations that are based on their own set of performance-based ethics. The nine areas include:

- Accident analysis
- Reactor plant analysis and testing
- Fuel analysis and testing
- Nuclear materials safety
- Materials analysis
- Nuclear safeguards
- Security
- External factors; and
- Consequence analysis (through structured environmental impact studies)

There are three possible outcomes to the staff's licensing review: (1) approval of the applicant's application or amendment request, (2) denial of the application or request, or (3) approval with conditions. If the reviewer cannot make a finding of a reasonable assurance of safety, the reviewer may consider proposing a license condition. Absent an NRC order, license conditions must be agreed on with the licensee or applicant before becoming part of the license. A license condition should only be proposed if there is reasonable assurance that, if the licensee meets the condition, all regulatory requirements will be satisfied.

1.6.1 Standard Review Plans and Guidance Documents for Nuclear Power Plants

The NRC develops and issues Standard Review Plans (SRP) and several types of guidance documents for use in the SMR license application review process. Example guidance documents produced include Regulatory Issue Summaries (RIS), Regulatory Guides (RG), a variety of SECY documents, and other types of guidance information. Example guidance documents developed to date that are applicable to SMRs are discussed below.

NUREG-0800

NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition," prescribes standard review procedures used by the NRC in its reviews of safety analysis reports submitted as part of license applications for nuclear power plants. The SRP provides guidance to NRC staff in performing safety reviews of construction permit (CP) or operating license (OL) applications (including requests for amendments) under 10 CFR Part 50 and early site permit (ESP), design certification (DC), combined license (CL or COL), standard design approval (SDA), or manufacturing license (ML) applications under 10 CFR Part 52 (including requests for amendments).

NRC issued a final revision to the SRP "Introduction – Part 2, SRP for the Review of Safety Analysis Reports for Nuclear Power Plants: Light-Water Small Modular Reactor Edition" section of NUREG-0800, "SRP for the Review of Safety Analysis Reports for Nuclear Power Plants" in early 2014. Part 2 is a new SRP section not previously included in NUREG-0800, and provides an overview of the "Risk-Informed and Integrated Review Framework" review methodology to be used for SMR applications under 10 CFR Part 52, when applicants choose to participate in pre-application coordination with the NRC.

Applicants are not required to engage with the NRC in the pre-application activities described

In this SRP. NRC reviews of submittals by applicants that choose not to engage the NRC in pre-application activities associated with development of a Design-Specific Review Standard (DSRS) would be performed using current SRP guidance and methods rather than using a DSRS in the risk-informed and integrated review framework discussed in this part of the SRP Introduction. However, the NRC believes that early engagement with the NRC as described in this review framework will positively benefit all review process stakeholders. Additional details pertaining to the use of a DSRS in a review of an SMR license application by the NRC are presented in Section 1.6.2.1 below.

Draft Revision 3 to NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition," Chapter 19.0, "Severe Accidents" (NRC 2007), states that for applicants seeking approval of an application for a plant containing multiple modules, the staff will review an applicant's assessment of risk from accidents that could affect multiple modules. Multi-module risk is discussed in additional detail in Section 1.6.3.2 below.

Regulatory Issue Summaries

NRC Regulatory Issue Summary (RIS) 2013–18, *Licensing Submittal Information And Design Development Activities for Small Modular Reactor Designs*, applies to applicants for a power reactor early site permit (ESP), combined license (COL), standard design certification (DC), standard design approval (DA), or manufacturing license (ML) siting a SMR design under Title 10 of the *Code of Federal Regulations* (10 CFR) Part 52, "Licenses, Certifications, and Approvals for Nuclear Power Plants", or applicants for a power reactor construction permit (CP) siting an SMR design under 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities."

As an example of how the RISs are used in the review of SMR license applications, in RIS 2013-18, the NRC requested information from potential future SMR licensees regarding certain application submittals related to SMRs to help the NRC in developing its budget process and review plans for review of future SMR license applications (NRC 2013b). NuScale responded to NRC RIS 2013-18 on December 30, 2013. The NuScale response indicated an evaluation was underway of the impact of the later-than anticipated U.S. DOE announcement that NuScale was selected as an award recipient under its "Cost-Shared Industry Partnership Program for Small Modular Reactors" on the design certification application (DCA) submittal date. In a letter to NRC dated March 10, 2014 (NuScale 2014), NuScale indicated that, based on their evaluation, they intend to submit the DCA in the second half of calendar year 2016.

In RIS 2014-07, the Nuclear Regulatory Commission (NRC) requested information from potential future SMR licensees regarding on contractors, vendors (CN) and suppliers of basic component and safety-related services (NRC 2014b). The information is intended to assist the NRC is planning and prioritizing its resources for responding to pending/anticipated SMR license applications.

Regulatory Guides

Regulatory Guides (RG) are issued by the NRC to provide license applicants with a methodology, approach, and consensus technical standards that are broadly acceptable to NRC in determining whether a proposed facility meets applicable NRC regulations. RGs are advisory in nature, not regulations. License applicants can suggest their own technical approaches toward complying with the applicable NRC rules and regulations. Currently there are over 200 RGs for power reactors. Some of these are specific to operating LWRs, while others are technology-neutral and could apply to any reactor design.

NRC RG 1.70, "*Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants*", provides the format and content of the Safety Analysis Report (SAR) that the license applicant for a new plant must provide to the NRC. The SAR informs the NRC of the nature of the plant, the plans for its use, and the safety evaluations that have been performed to evaluate whether the plant can be constructed and operated without undue risk to the health and safety of the public.

NRC RG 1.206, "*Combined License Applications for Nuclear Power Plants (LWR Edition)*", applies to applications for COLs for nuclear power plants. Information provided in this regulatory guide is reflected in NUREG-0800. This regulatory guide contains or refers to information collections covered by the requirements of 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," and 10 CFR Part 52, "Licenses, Certifications, and Approvals for Nuclear Power Plants".

NRC RG 1.206 provides guidance with regard to the following topical information that needs to be provided by all applicants for a COL for a nuclear reactor:

- Final Safety Analysis Report (FSAR)
- Inspection, Test, Analysis, and Acceptance Criteria (ITAAC)
- Probabilistic Risk Assessment (PRA)
- Environmental Report
- Security Plan
- General and Financial Information; and
- Quality Assurance (QA) Program Description

Section C.I.1.2, "General Plant Description", of this RG provides guidance regarding information that should be submitted that pertains to the facility design, including information supplemental to that included in the referenced certified design, such the principal design criteria and operating characteristics, safety considerations, and site-specific features of the plant likely to be of special interest because of their relationship to safety.

Section C.I.1.9 of this RG also lists additional regulatory documents that NRC wants an applicant for a new reactor to consider and address as appropriate.

SECY Documents

NRC staff have developed and submitted several SECY issue papers to the NRC's Commission to inform them about policy, rulemaking, and adjudicatory matters that are relevant to the licensing of SMRs. A number of SECY issue papers submitted to date that are applicable to SMRs are listed in the following section.

A series of other NRC RGs and other guidance documents, including Staff Requirements Memoranda, and other technical memos contain information that is applicable to the siting, design, and licensing of SMRs.

Table 1 provides a summary of key regulations and regulatory guidance documents that are relevant to the design and licensing of SMRs. A brief discussion of anticipated potential issues and/or obstacles or benefits of these regulatory requirements and applicable guidance with respect to the future licensing of SMRs is included in the last column of the table.

Table 1. Key Regulatory Requirements/Guidance Relevant to Licensing of Small Modular Reactors

Applicable Regulatory Guidance	Key Topics/Issues Addressed	Potential Issue/Obstacle or Benefit for SMR Licensing
Applicable Regulatory Requirements		
10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities"	Specifies requirements for the following (e.g., 10 CFR 50.34, "Contents of Applications; Technical Information"; and 10 CFR 52.47, "Contents of Applications; Technical Information"): • NPP Siting and Licensing Requirements • Design-Basis Accident Modeling Multi-unit accidents are not considered in the safety assessment technical information requirements for applications under 10 CFR 50. Final safe-shutdown earthquake (SSE) ground motion developed for site must satisfy requirements of Appendix S, "Earthquake Engineering Criteria for Nuclear Power Plants," to 10 CFR Part 50.	No new regulations are likely to be required for licensing of SMRs. Anticipate SMR licensees will conduct analyses of postulated core melt design-basis accidents (such as a Loss-of-Coolant Accident [LOCA]) in accordance with these pre-existing regulatory requirements. Issues related to potential accidents at multi-module SMRs are expected to be addressed through NRC guidance documents currently being developed.
10CFR Part 52, ""Licenses, Certifications, and Approvals for Nuclear Power Plants"	Governs issuance of early site permits, standard design certifications, combined licenses, standard design approvals, and manufacturing licenses for nuclear power facilities licensed under Section 103 of the Atomic Energy Act of 1954, as amended	No new regulations are likely to be required for licensing of SMRs. Issues related to potential accidents at multi-module SMRs are expected to be addressed through NRC guidance documents currently being developed.

Applicable Regulatory Guidance	Key Topics/Issues Addressed	Potential Issue/Obstacle or Benefit for SMR Licensing
	(68 Stat. 919), and Title II of the Energy Reorganization Act of 1974 (88 Stat. 1242). Multi-unit accidents are not considered in the safety assessment technical information requirements for applications under 10 CFR Part 52.	
10 CFR Part 100, "U.S. Code of Federal Regulations, "Reactor Site Criteria," Part 100, Chapter I, Title 10, "Energy."	Subpart A to 10 CFR Part 100 (applied to siting of nuclear power plants prior to January 10, 1997) provided considerations related to assessing accidents at multi-unit nuclear power plants. The final SSE ground motion determined through regional/local seismic hazard characterization must satisfy 10 CFR 100.23 requirements.	Issues related to potential accidents at multi-module SMRs are expected to be addressed through NRC guidance documents currently being developed. Information expected to become available from an updated seismic hazard in progress for the nearby Columbia Generating Station site, augmenting information available from previous permitting/licensing efforts for the WNP-1 site, may help inform/expedite the SMR licensing process, e.g., if SMR is sited at nearby WNP-1 site.
10 CFR 20.1301, 10 CFR 20.1302, "10 CFR Part 20—Standards for Protection Against Radiation, Subpart D--Radiation Dose Limits for Individual Members of the Public, "20.1301- Dose Limits for Individual Members of the Public; and 20.1302- Compliance with Dose Limits for Individual Members of the Public"	These provisions specify radiation dose limits for members of the public from nuclear reactors. For radioactive effluent releases, 10 CFR 20.1301(e) requires that NRC-licensed facilities comply with the U.S. Environmental Protection Agency's generally applicable environmental radiation standards of 40 CFR Part 190 for facilities that are part of the fuel cycle. These radiation standards require that all potential sources of external radiation and radioactivity be considered.	Additional work may be needed regarding characterization of radiological sources terms for SMRs (see discussion under "RG 1.183" below).
NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition."	Specifies requirements for conducting design-basis accident analyses for large light-water reactors or light-water SMRs.	TBD
Regulatory Guides (Nuclear Regulatory Commission)		
RG 1.29, "Seismic Design Classification"	Identifies SSCs of a nuclear power plant, including foundations and supports, that are designated as Seismic Category I and that must be designed to withstand the effects of, and remain functional, if a SSE ground motion were to occur	Information expected to become available from an updated seismic hazard in progress for the nearby Columbia Generating Station site, may help inform/expedite the SMR licensing process, e.g., if SMR is sited at nearby WNP-1 site.
RG 1.45, "Guidance on Monitoring and Responding to Reactor Coolant System Leakage"	Provides guidance on specific items related to reactor design basis including methods used for collecting, characterizing, classifying, and monitoring any Reactor Coolant Pressure Boundary leakage into the reactor containment vessel. Includes provisions for testing and calibrating the	Licensing reviews related to these requirements may be facilitated/expedited for an mPower SMR or a NuScale SMR because: • NRC has developed a DSRS for addressing these requirements

Applicable Regulatory Guidance	Key Topics/Issues Addressed	Potential Issue/Obstacle or Benefit for SMR Licensing
	components and instrumentation used for leakage detection.	when reviewing possible future SMR design submittals for an mPower SMR; and • NuScale Power is working with the NRC to develop a modified version of this DSRS that accommodates certain design differences between the NuScale Power SMR and the mPower SMR.
RG 1.60, "Design Response Spectra for Seismic Design of Nuclear Power Plants" , Rev. 2, July 2014	• Describes approach that NRC staff considers acceptable for defining response spectra for the seismic design of nuclear power plants to satisfy the requirements of Appendix A, "Seismic and Geologic Siting Criteria for Nuclear Power Plants," to Part 100, "Reactor Site Criteria," of Title 10 of the *Code of Federal Regulations* (10 CFR Part 100). • The SSE ground motion for these nuclear power plants is defined by a RG 1.60 response spectrum	Allows applicants and licensees to voluntarily provide information that adequately addresses this guidance for demonstrating compliance with the underlying NRC regulations, likely facilitating NRC's review of seismic response spectra information. This revised RG contains (pre-approved) certified seismic design response spectra that were defined through previous analyses completed for NPPs in the Western U.S. and have been amended with modified control points to broaden the spectra in the higher frequency range. Information expected to become available from an updated seismic hazard in progress for the nearby Columbia Generating Station site, augmenting information available from previous permitting/licensing efforts for the WNP-1 site, may help inform/expedite the SMR licensing process, if SMR is sited at the nearby WNP-1 site.
RG 1.81, Revision 1, January 1975, "Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants"	Through a periodic review of RG 1.81, Rev. 1, in 2014 NRC staff y determined that this RG should be updated/revised to endorse requirements of 10 CFR 50.55a(h), IEEE 603-2009, "IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations," and IEEE 308-2012, "IEEE Standard Criteria for Class IE Power Systems for Nuclear Power Generating Stations"	TBD
RG 1.132, Rev. 2, "Site Investigations for Foundations of Nuclear Power Plants"	Describes field investigations for determining the geological, engineering, and hydrogeological characteristics of a prospective nuclear power plant site. Provides guidance for developing geologic information on stratigraphy, lithology, and structure of the site.	Information available from previous permitting/licensing efforts for the WNP-1 site and expected to become available for the nearby Columbia Generating Station site should help inform/expedite the SMR licensing process, if SMR is sited at the WNP-1 site.
RG 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors"	Provides guidance for characterization of radiological source terms for design-basis accident analysis	SMR designers may use, as applicable, guidance in this RG to determine (e.g., limit) which design-basis accidents are analyzed (except as precluded as not credible by design features) and for the majority of the

Applicable Regulatory Guidance	Key Topics/Issues Addressed	Potential Issue/Obstacle or Benefit for SMR Licensing
		assumptions used in the design-basis accident analyses. NRC staff have had several interactions with a number of potential SMR design applicants regarding their Mechanistic Source Term (MST) methodology. The mPower and NuScale SMR source term white papers both propose to take credit for passive fission product removal processes, such as natural deposition in containment (previously found acceptable for large light-water reactors). Acceptance by the NRC of the SMR MST characterization and analyses submitted by such SMR applicants could help expedite NRC's review/approval of future SMR license applications.
RG 1.206, "Combined License Applications for Nuclear Power Plants (LWR Edition)"	Provides guidance for reactor licensees when preparing the following COL license application items: • *Final Safety Analysis Report (FSAR)* • *Inspection, Test, Analysis, and Acceptance Criteria (ITAAC)* • *Probabilistic Risk Assessment (PRA)* • *Environmental Report* • *Security Plan* • *General and Financial Information* • *Quality Assurance (QA) Program Description*	TBD
RG 1.208, "A Performance-Based Approach to Define the Site-Specific Earthquake Ground Motion"	Provides guidance on development of the site-specific ground motion response spectrum (GMRS). The GMRS represents the first part of the development of the SSE ground motion for a proposed nuclear reactor site.	Information expected to become available from an updated seismic hazard in progress for the nearby Columbia Generating Station site, augmenting information available from previous permitting/licensing efforts for the WNP-1 site, may help inform/expedite the SMR licensing process, if SMR is sited at the nearby WNP-1 site.
RG 1.215, Rev.1, "Guidance for ITAAC Closure Under 10 CFR Part 52"	Describes a method NRC staff considers acceptable for satisfying requirements for documenting completion of ITAAC. This guide endorses methodologies described in industry guidance document Nuclear Energy Institute (NEI) 08-01, "Industry Guideline for the ITAAC Closure Process under 10 CFR Part 52," Revision 4, issued July 2010.	TBD
SECY Documents (Nuclear Regulatory Commission)		
SECY-11-0024, "Use of Risk Insights To Enhance	Directs NRC staff to use the risk-informed and integrated review framework for staff pre-application and application review	NRC is currently undertaking expanded scope pre-application activities, including developing pre-application, licensing, and

Applicable Regulatory Guidance	Key Topics/Issues Addressed	Potential Issue/Obstacle or Benefit for SMR Licensing
the Safety Focus of Small Modular Reactor Reviews"	activities related to design applications for integral pressurized-water reactors.	project plans for the Advanced Reactor Program, soliciting information through issuance of Regulatory Issue Summaries to potential SMR licensees, and developing risk-based guidelines for future NRC reviews of SMR design submittals. This is expected to allow for taking advantage of lessons learned from recently completed NRC reactor design reviews.
SECY-10-0034, "Potential Policy, Licensing, and Key Technical Issues for Small Modular Nuclear Reactor Designs"	Relates to NRC review of a license review application (for design approval or design certification under 10 FCR Part 52). Application could involve a request for approval of a combined license, manufacturing license, or early site permit under 10 CFR Part 52, or a request for a construction permit and operating license under 10 CFR Part 50. Informs the NRC of potential policy, licensing, and key technical issues related to the following topics regarding design and license review applications for SMRs and establishes guidance for NRC Staff plans and schedules for resolution of these issues: • *Implementation of the Defense-In-Depth Philosophy for Advanced Reactors* • *Appropriate Source Term, Dose Calculations, and Siting for SMRs* • *Appropriate Requirements for Operator Staffing for Small or Multi-Module Facilities* • *Security and Safeguards Requirements for SMRs*	Pursuant to guidance provided in this SECY document, NRC staff is currently developing detailed resolution plans for resolving each issue/topic expected to be included in an SMR license application. Anticipate that these pre-established issue resolution plans may help facilitate issue resolution and thus expedite the SMR licensing process.
SECY-11-0079, "License Structure for Multi-Module Facilities Related to Small Modular Nuclear Power Reactors"	Addresses process for licensing multi-module plants, including legal considerations. This SECY discussed the following three options for licensing SMRs and committed to further develop the specific aspects of alternative 3 and submit a specific proposal to the NRC for approval: (1) Single license for the facility (2) Master facility license, and (3) Individual reactor module licenses. Does not address multi-module risk.	Issues related to potential accidents at multi-module SMRs are expected to be addressed through NRC guidance documents currently being developed.
SECY-11-0152, "Development of an Emergency Planning and	Discusses NRC staff's intent to develop a technology-neutral, dose-based, consequence-oriented emergency	The NEI prepared a White Paper in December 2013 describing a proposed methodology and criteria for establishing the

Applicable Regulatory Guidance	Key Topics/Issues Addressed	Potential Issue/Obstacle or Benefit for SMR Licensing
Preparedness Framework for Small Modular Reactors"	preparedness framework for SMR sites that takes into account the various designs, modularity and collocation, as well as the size of the emergency planning zone.	technical basis for SMR plume exposure emergency planning zone sizing. NRC issued a series of questions to the NEI in June 2014 on the December 2013 NEI White Paper. Sufficient resolution of these questions will be necessary to help preclude potential delays in NRC's review of future SMR license applications

1.6.1.1 Existing Regulations and NRC Guidance Documents Developed for SMRs

In general, NRC expects that current regulations are broad enough that they can be applied to light-water SMRs. Section 1.6.4 above and Table 1 summarize existing regulatory requirements that are applicable to the licensing of SMRs. In addition, to date, the NRC has already developed several draft or final guidance documents that it intends to use to help facilitate their review of license applications for SMRs. Among such documents are the following:

- **SECY-10-0034**: Potential Policy, Licensing, and Key Technical Issues for Small Modular Nuclear Reactor Designs
- **SECY-11-0024**: Use of Risk Insights to Enhance the Safety Focus of Small Modular Reactor Reviews
- **SECY-11-0079**: License Structure for Multi-module Facilities Related to Small Modular Nuclear Power Reactors
- **SECY-11-0098**: Operator Staffing for Small or Multi-module Nuclear Power Plant Facilities
- **SECY-11-0112**: Staff Assessment of Selected Small Modular Reactor Issues Identified in SECY-10-0034
- **SECY-11-0152**: Development of an Emergency Planning and Preparedness Framework for Small Modular Reactors
- **SECY-11-0178**: Insurance and Liability Regulatory Requirements for Small Modular Reactor Facilities
- **SECY-11-0181**: Decommissioning Funding Assurance for Small Modular Nuclear Reactors
- **SECY-11-0184**: Security Regulatory Framework for Certifying, Approving, and Licensing Small Modular Nuclear Reactors
- **Commission Memo**: Status of Staff Activities to Address Mechanistic Source Term Methodology (12/29/11)
- **Commission Memo:** Staff Assessment of the Manufacturing License Requirements Issue for Small Modular Reactors (3/27/13)
- **Commission Memo:** Current Status of the Source Term and Emergency Preparedness Policy Issues for Small Modular Reactors (5/30/13)
- **Commission Memo**: Update Regarding Recommendations for Use of Risk Insights for Small Modular Reactor Reviews (1/30/14)

The above notwithstanding, SMR design, licensing, and detailed engineering activities are still in the development stage. Licensing and design certification documents are expected to be ready for NRC filing in approximately the 2015 time frame. Cost data currently publicly available are preliminary, and current estimates still have a substantial amount of uncertainty. Cost estimates developed for GigaWatt-level reactors have significantly greater person-hours already expended in this early engineering design work as compared with design work carried out for SMRs to date.

Although SMRs use the same fuel type and the same light water cooling as gigawatt (GW)-scale light water reactors (LWRs), there are significant differences in the reactor design for SMRs compared to large-capacity LWRs and some significant enhancements in the SMR design that should contribute to an upgraded safety case for SMRs. For example, some entities such as the Nuclear Energy Institute (NEI) have assumed that there is "the expectation of enhanced safety inherent in the design of SMRs (e.g., increased safety margin, reduced risk, smaller and slower fission product accident release, and reduced potential for dose consequence to population in the vicinity of the plant)." (e.g., NEI White Paper, December 2013 [NEI 2013a])

In June 2014, the NRC issued a series of questions to NEI regarding in response to this White Paper, including questions regarding what key design features and operational programs are to be relied upon for this to be a good assumption, particularly the slower fission product accident release and reduced potential for dose consequence; whether a method for determining source terms for multi-module core damage events needs to be developed; whether additional information and additional model case studies will need to be developed in order to demonstrate that the MELCOR Accident Consequence Code System (MACCS) code is an appropriate tool to calculate consequences for the analyses for SMRs (given that this code has not previously been used for SMR analyses to support emergency planning zone sizing, and other additional questions, including how insights obtained from the Fukushima reactor accident will be incorporated into accident analyses in license application documents for SMRs.

1.6.2 Design-Centered Review Approach for SMR Applications

The NRC intends to use a design-centered review approach (DCRA) strategy for managing the licensing review workload. To meet that objective, NRC has issued RISs to potential SMR licensees requesting updated information to aid the agency's schedule and resource planning efforts. The NRC outlined the DCRA in RIS 2006-06, "New Reactor Standardization Needed To Support the Design-Centered Licensing Review Approach," dated May 31, 2006 (http://www.nrc.gov/reading-rm/doc-collections/gen-comm/reg-issues/2006/ri200606.pdf). The DCRA is a review strategy for COL applications that cite a particular design.

Using this approach, NRC intends to use, to the maximum extent practicable, a "one issue, one review, one position" strategy to optimize the review effort, the resources needed to perform these reviews, and the review schedules. Specifically, the staff intends to conduct one review for each issue associated with a particular design, reach a decision on each issue, and, if possible, rely on that decision in reviewing subsequent applications. The NRC indicates that applicants must achieve a consistent level of standardization for the DCRA to be fully effective (NRC 2013b).

1.6.2.1 Design-Specific Regulatory Standards

Regarding review standards, the same NRC regulations apply to SMRs as apply to larger, conventional LWRs:

- Existing NUREG-0800 (Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition) Standard Review Plans are used for SMRs when they apply.
- DSRSs are prepared for SMRs where the SRPs do not apply as written.
  - DSRSs have the same format and content as the SRPs provided in NUREG-0800 that are used for large, light water reactors.

NRC has developed a DSRS for the B&W mPower DSRS, which it intends to apply during its review activities associated with a B&W mPower™ SMR design-related design certification (DC), combined license, or early site permit application under 10 CFR Part 52.

SMR designers such as B&W and NuScale and the NRC have identified and have submitted a number of topical reports as part of pre-application activities that are foundational to the DCA review. SMR designers are expected to continue to submit required topical reports for NRC review in the period following the completion of the draft DSRS development. These topical results may include:

- Results from testing programs already underway or completed
- Analytical code descriptions and validation work
- A range of topical reports on unique features of specific SMR designs to support NRC confirmatory analysis tool development
- Similar long review- duration information supporting the SMR licensing basis.

Issuance of draft DSRSs provides regulatory stability to support moving to the next phase of pre-application activities. Having a draft DSRS provides SMR designers such as NuScale or others with greater confidence that the work they are performing will meet NRC expectations. This approach reduces the likelihood of changes driven by new or different DSRS expectations occurring late in the design certification application (DCA) preparation process that delay or complicate the DCA review, DC rulemaking, client COLA development, or, ultimately, construction. This situation has occurred for other design applicants and licensees and has significantly impacted their schedules as documented in the NRC's "New Reactor Licensing Process Lessons Learned Report," dated April 16, 2013 (ML13059A239).

For the NuScale SMR(and/or other alternative SMR designs, the potential exists for capitalizing on the availability of the same NRC staff that were substantially involved in the development of the mPower DSRS and the NuScale pre-application program to develop a high-quality DSRS. As of August 2103, NRC estimated that about 90% of the DSRS sections done for the mPower™ SMR were applicable to the NuScale SMR with minor or no changes (NRC 2013a).

For consistency in format and content (where applicable) and to maximize efficiencies, NRC Technical Branches are currently using the B&W mPower SMR DSRSs as the starting basis to prepare NuScale SMR– specific DSRSs. It is expected that a similar approach would be implemented by NRC in reviewing pre-application submittals and license applications submitted for other SMR designs.

1.6.2.2 NRC Audit/Review Programs

The NRC conducts audit/review programs to help facilitate review of SMR design submittals. As an example, in the time period between June 5, 2014, and September 30, 2014, NRC staff will periodically review documents located at the NuScale local office located at Rockville, MD

(NRC 2014a). The purpose of this audit is to review internal NuScale draft documentation of the NuScale SMR design, to allow Office of New Reactors (NRO) technical staff to gain a better understanding of the SMR design during the pre-application phase of activities. Review of these documents is not intended to be used to reach a regulatory decision but rather to assist in developing the DSRS that will assist the NRC staff in reviewing the NuScale design if submitted to the NRC for review. Topics to be addressed in NRC pre-application audits/reviews meetings scheduled to date (late July 2014) for the NuScale SMR include:

- Effects of flow-induced vibration on the reactor vessel internals in the NuScale SMR design;
- ASME piping design;
- Update on NuScale Testing Program, including:
  - Phenomena Identification and Ranking Table (PIRT) Phenomena and Processes (e.g., NRC 2008)
  - Scaling Basis
  - Facility Upgrades and New Capabilities
  - Testing Completed and Planned for Design
  - Certification
  - RELAP5-3D Code-to-Test Data Predictions (RELAP5-3D is a generic code that, calculates the behavior of a reactor coolant system during a transient and that can be used for simulation of a wide variety of hydraulic and thermal transients in both nuclear and non-nuclear systems); and
- Approach to In-service Inspection (ISI), In-service Testing on (IST), and Appendix J (which specifies containment leakage test requirements for primary reactor containment and systems and components which penetrate containment systems for water-cooled reactors).

DSRSs developed for the Generation mPower SMR and NuScale SMR, and future DSRSs that may be developed by the NRC for other SMR designs will be used to facilitate review of the specific SMR designs if the SMR manufacturer submits a design certification application. It is expected that this audit/review program will help expedite the schedule for NRC's review of ongoing and future SMR design submittals.

1.6.3 Specific Technical/Licensing Issues for SMRs

1.6.3.1 Modularization

The NuScale SMR is a modularized nuclear power generating facility. Modularization is the prefabrication of sections of a plant executed either off-site in specialized factories or within the site perimeter in specially reserved and protected areas. Modularization allows the application of parallel construction techniques whereby civil, mechanical and electrical work can proceed for the most part in parallel.

Without modularization, in conventional construction, the mechanical, electrical and I&C installations are carried out exclusively in situ inside the buildings where they will be permanently located. Installation in such cases must wait until the civil work is complete.

Modularization typically implies that a substantial amount of work required for constructing the reactor component (modules) is outsourced to off-site locations. This approach should allow for savings in labor costs for the Owner/Operator in terms of salary disbursements, per diems, accommodation and overheads. The IAEA suggests this cost savings may be much as 40%. A smaller labor force on-site also allows for reduced congestion of workers and equipment, which should reduce inefficiencies from possible work activity interferences, as well as reduce the risks of cost overruns associated with on-site congestion, increased training and required sequencing of such activities. Other cost reductions may be realized due to more controlled or more advanced construction support systems lees complicated material management.

Modularization of construction of nuclear power plant modules would be expected to result in lower disturbances to the local environment, and in reductions in amounts of generated material wastes, dust and noise, than more conventional, larger-scale nuclear power generating facilities.

1.6.3.2 Multi-Module Risk

10 CFR 50, Appendix A, General Design Criteria (GDC) 5, "Sharing of Structures, Systems, and Components," states that structures, systems, and components (SSC) important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, the shutdown and cool-down of the remaining units.

At the time this report was being prepared, the NRC has developed draft proposed evaluation criteria for specifically assessing "multi-module" risk, i.e., for evaluating the risk of accidents involving multiple units (modules) of a SMR. In developing the draft multi-module guidance document discussed in the above paragraph, the only radiological source that was considered were the reactor cores. These draft evaluation criteria were provided in "Multi-Module Risk: NRC Draft Technical Guidance" (NRC 2014c). Multi-module risk, and the analysis of that risk, is an issue for any nuclear power station that consists of more than one nuclear power module (i.e., a nuclear power reactor and its associated safety and control features). A multi-module nuclear power station or nuclear power plant contains multiple nuclear power modules wherein: "a) each module can be safely operated independent of other modules, and" b) all modules are located within a common building structure such that a module can be physically impacted by events occurring at another module due to proximity and lack of a physical barrier providing separation" (NRC 2014c). A multi-module nuclear power station might have some shared or common systems.

The NRC Office of Nuclear Regulatory Research (RES) is developing an integrated Level 3 Probabilistic Risk Assessment (PRA) that includes the effects of multiple units, as well as the risk from all radiation sources onsite, including the spent fuel pool. NRC is evaluating options regarding their possible endorsement of ASME American Nuclear Society (ANS) PRA standards in connection with its multi-module risk assessment efforts.

SMR applicants are currently considering multi-module risk as part of their license application submittal. NRC staff have created an Issue Identification and Ranking Project to identify other multi-module issues.

The draft criteria include NRC verification that: (i) the SMR applicant has used a systematic process to identify accidents sequences, including significant human errors, that is they were to occur, could lead to multiple module core damages or large releases; and (ii) The SMR applicant has included operational strategies that provide reasonable assurance that there is sufficient ability to mitigate possible multiple core damage accidents.

The NRC expects to finalize the draft multi-module risk criteria and incorporate them into Chapter 19.0, Severe Accidents", of the Standard Review Plan (NUREG-0800). As these criteria are finalized, NRC will evaluate external hazards and their relationship to multi-module risk, and consider and address other relevant guidance, such as that being developed by the IAEA in its Technical Approach to Multi-Unit Probabilistic Safety Assessment Safety Report, in preparation.

1.6.3.3 Radiological Source Term Characterization

The Nuclear Energy Institute (NEI) submitted a position paper, "Small Modular Reactor Source Terms," on December 27, 2012 (ADAMS Accession No. ML13004A390). The paper established the NEI Licensing Task Force's positions on accident radiological source terms and related issues. The white paper was developed on the premise that SMRS can be licensed within the existing regulatory framework. The NEI position paper is primarily focused on pressurized-water SMRs.

NRC staff indicated in public meetings that the NEI position paper provided a good outline of options for the development of design-specific source terms but that more details and research plans were needed in additional papers or technical reports in order to validate design-specific evaluations that will be required for SMRs. NRC staff have subsequently had interactions with potential SMR design applicants regarding their Mechanistic Source Term (MST) methodology. Interactions have been conducted with Generation mPower LLC, NuScale Power, and DOE/Idaho National Lab's (INL) Next Generation Nuclear Plant. These interactions have focused on design-specific activities regarding their accident source term position papers.

In 2012 and 2013, B&W Generation mPower and NuScale submitted position papers describing their proposed approach for developing radiological source terms, assessing radiological consequences of design-basis accidents, and methodologies for crediting specific SMR design features in meeting current regulatory expectations established in 10 CRF Part 100, 10 CRF 50.34 (a)(1), and 10 CFR Part 52. Both the mPower and NuScale source term White Papers propose to take credit for passive fission product removal processes, such as natural deposition in containment, which have been previously found acceptable for large light-water reactors. It is worth noting in this regard that a potential design/performance advantage that SMRs may have over conventional pressurized light-water reactors is that such scenarios may potentially result in a delay of several days before core damage and fission product release.

This result, if accepted by NRC upon review of the DCA submittal for a new SMR that demonstrates this finding, can be compared with currently accepted modeled results for pressurized and boiling-water reactors, in accordance with the guidance provided in Regulatory Guide 1.183, of a time delay after the pipe break of 30 seconds for pressurized-water reactors, 2 minutes for boiling-water reactors, or 10 minutes for plants of either type that have an accepted credit for a leak occurring before pipe break. According to the NRC (NRC 2014 d), this several-day delay in core damage would result in a large reduction in the I-131 release, which is often a major contributor to dose for design-basis accident analyses for conventional LWRs. If accepted, this could help expedite NRC's review/approval of future SMR license applications such as NuScale Power or mPower SMRs, or other SMRs which take credit for passive fission product removal processes. The NRC has not previously allowed such credit of emergency core-cooling system operation for large light-water reactors, including passive plants.

1.6.3.4 Inspections, Tests, Analyses, and Acceptance Criteria

ITAAC are a fundamental element of the licensing process established in 10 CFR Part 52. 10 CFR 52.47 contains requirements governing the technical contents of a design certification application (DCA) for nuclear reactors, including SMRs. 10 CFR 52.47(a) requires that the DCA contain a final safety analysis report. 10 CFR 52.47(b)(1) requires that the DCA contain the proposed ITAAC that are necessary and sufficient to provide reasonable assurance that, if the ITAACS are performed and met, a facility that incorporates the design certification has been constructed and will be operated in conformity with the design certification, the provisions of the Atomic Energy Act, and the NRC's rules and regulations.

In December 2013, the NEI submitted a White Paper (NEI 2013b) to the NRC describing a proposed alternative approach for DCA submittals based upon a phased submittal of "Tier 1"/ITAAC and "Tier 2" information. NEI proposed an option to utilize a phased DCA submittal process in order to provide sufficient time for improvements to ITAACs for SMRs to be developed, and to permit a SMR DC applicant sufficient time to implement these improvements. NEI indicated that the approach would enhance regulatory efficiency and effectiveness by allowing additional time for generic improvements to SMR ITAAC, including overall ITAAC standardization, to be developed and implemented.

In March 2014, NEI submitted a White Paper NEI 29014a) that proposed improvements to Tier 1 and ITAAC for SMRs as a basis for discussion with the NRC. The goal is to standardize Tier 1 and ITAAC to the maximum extent practical and to enhance the efficiency of ITAAC review and implementation processes. The NEI indicted in this White Paper that the next Design Certification applications are expected to be for SMR designs, with a few currently scheduled to be submitted in 2014 and 2015. Therefore, NEI concluded that an expedited schedule to develop Tier 1 and ITAAC improvements is needed to enable the near-term applicants to benefit from these improvements. NEI also suggested that the set of standardized ITAAC types proposed in Appendix B (NEI 2014b): to the White paper is expected to encompass approximately 90% of the ITAAC for all near term SMR applicants. In addition, the paper describes proposed process enhancements that would mitigate the surge of ITAAC closures in the later stages of construction. The following top-level design areas will be addressed by ITAAC (NEI 2014b):

- Reactor Coolant Pressure Boundary (RCBP) (Fission Product Barrier);
- Containment Pressure Boundary (Fission Product Barrier);
- Post-Accident Core Cooling;
- Control Room Habitability;
- Protection of Safety-Related Structures Against Natural Phenomena and Environmental Hazards;
- Power Sources Necessary to Support Safety-Related SSCs;
- I&C Systems Necessary to Provide Reactor Protection and Engineered Safeguards Equipment Actuation;
- Radiation Protection(Radiation Shielding, Confinement, Ventilation, Isolation, Monitoring);
- Fire Protection;
- New and Spent Fuel Protection; and
- Physical Security.

In its 2014 White Paper, NEI requested that, in order to support near-term DC applicants, issuance of final guidance and NRC endorsement of ITAAC improvements is desired by the end of 2014. Staff at the NRC indicated that they plan to update the guidance on ITAAC in the SRP, NUREG-0800 Section 14.3.

1.6.4 Relevancy of Prior Siting/Permitting Work: WNP-1 and WNP-4 Reactor Sites

The WNP-1 and adjacent WNP-4 sites are located on a portion of the Hanford Reservation in Washington State that the permittee has leased from the DOE. The environmental impacts associated with the construction of the facility have been previously discussed and evaluated in the Final Environmental Statement (FES) prepared as part of the NRC staff's review of the construction permit application, NUREG-75/012, March 1975.

The WNP 1/4 units were co-located with WNP-2 on an unrestricted portion of the Hanford site. The NRC issued a Construction Permit (No. CPPR-134) to Washington Public Power Supply System (WPPSS), the permittee, now doing business as Energy Northwest, for the Nuclear Project No. 1 (WNP-1). The construction contract for WNP-1 was signed on 6 Feb 1973. However, WNP-1 construction was stopped in May 1982 at about 65% completion. For 12 years, the partially constructed facility was maintained in that condition. A final termination decision was made in 1994 after intermittent discussion of using the facility as a production reactor.

In a letter to the NRC in 2001, Energy Northwest indicated that resumption of construction activities at WNP-1 (which was under consideration at that time) would not be expected to cause adverse impacts to any listed aquatic or terrestrial species or their habitats, indicating that in-river construction work and all significant earthmoving activities had already been completed. Energy Northwest also noted that completing construction of, and operating the WNP-1 facility would also allow experience gained at the neighboring Columbia Generating Station (having the same intake and outfall design as that of the partially completed WNP-1 facility) to be applied to the environmental impacts evaluation process for construction/operation of WNP-1 facility, including potential impacts of water withdrawals and discharges on aquatic species during construction and operation of the facility (NRC 2002).

A permit was previously issued by the U.S. Army Corps of Engineers (USACE) for the submerged river water intake structure. That intake structure has not been abandoned/ removed and could be utilized for an SMR constructed at the WNP-1 site. If Energy Northwest decides to abandon the intake structure, the USACE permit requires that Energy Northwest restore the area to a condition satisfactory to the district engineer (Federal Register 2006).

The Construction Permit was terminated by the NRC, at Energy Northwest’s request, in early February 2007. Because the construction permit for Unit 4 (WNP-4) was effectively subsumed in the Unit 1 (WNP-1) construction permit on November 27, 1985, the NRC oversight of the proposed WNP-4 facility was also terminated.

1.6.4.1 Implications of Previous WNP-1 Licensing Activities for Licensing and Operation of an SMR at WNP-1 Site

Considering that the WNP-1 site already was previously issued a Construction Permit by the NRC, this would be expected to facilitate (streamline) the process for licensing a SMR at this location. There is significant documentation available for the WNP-1 site as a result of the previous WNP-1 permit application to the NRC and subsequent correspondence between the WPPSS and Energy Northwest and the NRC, including site characteristics, terrestrial ecology, prior agreements regarding site restoration requirements, and existing Energy Northwest/DOE area Lease Agreement requirements.

The WNP-1 and WNP-4 properties lie almost entirely within the Columbia Generating Station exclusion area, which is defined as all lands within a 1.2-mile radius of the Columbia Generating Station (WNP-2) and includes both leased and non-leased portions of DOE's lands. Additional cost savings might also be realized (e.g., including costs for emergency preparedness, nuclear security, operator training and used nuclear fuel storage) by locating a SMR at this location due to its proximity to Energy Northwest's full-scale commercial nuclear power plant.

1.6.5 Technological Advantages of SMRs Relative to Conventional Larger-Scale Nuclear Reactors

Generally, SMRs have several technological advantages that can affect the operation, safety, and security of the plant. Examples features of SMRs that may provide such advantages are passive safety features that utilize gravity-driven or natural convection systems – rather than engineered, pump-driven systems – to supply backup during upset conditions. The higher fuel burn up rates increases the length of the required refueling period and reduces the amount of waste generated. The smaller size can also potentially result in a reduced emergency planning zone, e.g., to less than the 10 miles required for current conventional operating nuclear power plants and a smaller footprint that a security force must protect.

The design and operation of SMRs can also result in reduced physical protection and plant security requirements. For example, the location of the reactors below ground in some SMR designs (e.g., NuScale SMR; B&W mPower SMR) helps protect the plant against external threats such as large explosive weapons or aircraft impacts.

1.6.6 Potential Cost-Saving Features of SMRs Relative to Conventional Larger-Scale Nuclear Reactors

One area where SMRs are expected to provide a significant cost savings without compromising safety and security is in the area of plant staffing. The design and operation of SMRs can result in reduced security staffing requirements. The reduced size of SMRs and the passive designs with inherent safety features utilized in most SMR designs can reduce the plant staffing. Operational staff may be reduced through the use of automated response features including advanced physical security features and shared control rooms. During upset conditions, passive safety features and lower levels of decay heat minimize the need for prompt operator actions to place the plant in a safe condition. In addition, the passive safety features of SMR designs will allow for additional delay time for security forces to respond to an incident.

1.6.7 Potential Cost Savings/Cost Avoidances for an SMR Cited at WNP-1 or WNP-4 Site

Owing to the immediate proximity of the WNP-1 and WNP-4 sites to the Energy Northwest Columbia Generating Station facility, where the site and surrounding areas conditions have been extensively studied and characterized and in some instances are currently undergoing further characterization and analysis, it is expected that a number of cost advantages (substantial cost avoidances) could be realized SMR were constructed and operated at either the WNP-1 site or the WNP-4 site, These cost savings/cost avoidances would occur in the areas of environmental, geologic/geotechnical, and seismological studies needed prior to submitting a license application for an SMR sited on either the WNP-1 or WNP-4 site, rather than at a previously uncharacterized or much less studied site/area. Examples pre-application activities where such potential cost savings/avoidances could be achieved are discussed in the following subsections.

Updated Site/Regional Seismic Hazard Evaluation

Energy Northwest is currently developing an updated Seismic Hazard Evaluation and Screening Report for the nearby (adjacent) Columbia Generating Station (CGS) facility to comply with NRC's request for information per 10 CFR 50.54(f), dated March 12, 2012 (Fukushima 50.54(f) letter). Energy Northwest has previously completed analyses of the operating basis earthquake and safe shutdown earthquake for the CGS. Volcanic hazards are also being reevaluated as part of the NRC’s review of EMW's Response to NRC Order EA-12-049, "Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond Design Basis External Events," March 12, 2012 (ADAMS Accession No. ML 12054A735).

Results of these analyses should reduce and could eliminate the need to complete an updated Seismic Hazard Evaluation for a nearby selected SMR site (e.g, WNP-1 or WNP-4).

Updated Site Subsurface Soil Investigation

Depending on the nature of additional site characterization data being acquired for the CGS to support the ongoing updated Seismic Hazard Evaluation and Screening Report and the reevaluation of volcanic hazards and their usability/applicability to the proposed SMR site location (e.g., WNP-1 or WNP-4 site), and the possible impact of new criteria/guidance, costs for completing a supplemental site subsurface soil investigation at the selected SMR site may be somewhat to substantially reduced.

Flood Hazard Evaluation/ Dam Breach Analysis

ENW is currently working with the U.S. Army COE and the NRC to prepare a dam breach analysis and complete an updated flood hazard reevaluation for the Columbia and Snake Rivers that also factors in the effects of a potential dam breach on the CGS facility. Results of these analyses could likely eliminate the need to complete an updated flood hazard and dam breach analysis for a nearby selected SMR site.

Environmental Report

ENW submitted an Environmental Report to the NRC for the CGS License Renewal Application in January 2010. This document presented and evaluated information on the major environmental resources areas and potential impacts of plant operations on these resources (terrestrial resources, aquatic resources (fish and shellfish), threatened and endangered species, air quality and water resources, microbiological organisms, historical and archeological resources, etc.).

An EA was also previously completed by the NRC for the previously proposed WNP-1 nuclear plant. The availability of this document and previous supporting site characterization studies, together with results from updated environmental studies to be completed for the Columbia Generating Station support the license renewal, should substantially reduce the costs for completing an Environmental Report for a selected nearby SMR site.

EIS or Updated Environmental Assessment Document

An Environmental Impact Statement (EIS) NUREG-1437, “Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Columbia Generating Station

[NUREG-1437, Supplement 47] Final Report for Comment") was published by the NRC in April 2012 to satisfy requirements of the National Environmental Policy Act (NEPA) and support the NRC's license renewal application review. These documents presented and evaluated information on the major environmental resources areas and potential impacts of plant operations on these resources (terrestrial resources, aquatic resources (fish and shellfish), threatened and endangered species, air quality and water resources, microbiological organisms, historical and archeological resources, etc.).

An Environmental Assessment (EA) was also completed for the proposed WNP-1 nuclear plant. The availability of this document and previous supporting site characterization studies, together with results from updated environmental studies completed for the Columbia Generating Station support the license renewal, should substantially reduce the costs for completing an updated environmental impact study or updated EA for a selected nearby SMR site.

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Acronyms and Abbreviations

ALWR	Advanced Light Water Reactor
ANS	American Nuclear Society
B&W	Babcock & Wilcox Co.
CFR	Code of Federal Regulations
CGS	Columbia Generating Station
CL/COL	Combined License
COE	(U.S). Army Corps of Engineers
CP	Construction Permit
DC	Design Certification
DCRA	Design-Centered Review Approach
DOE	U.S. Department of Energy
DSRS	Design-Specific Review Standard
EA	Environmental Assessment
EIS	Environmental Impact Statement
ENW	Energy Northwest
ESP	Early Site Permit
GW	Gigawatt
HASP	Health and Safety Plan
IAEA	International Atomic Energy Agency
INL	Idaho National (Energy) Laboratory
ISI	In-service Inspection
IST	In-service Testing
ITAAC	Inspections, Tests, Analyses, and Acceptance Criteria
MACCS	MELCOR Accident Consequence Code System
MD	Maryland
ML	Manufacturing License
MWe	Megawatt Equivalent
MST	Mechanistic Source Term
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NGNP	Next Generation Nuclear Plant
NRC	Nuclear Regulatory Commission
OL	Operating License
PRT	Phenomena Identification and Ranking Table
PRA	Probabilistic Risk Assessment
PWR	Power Water Reactor
RCPB	Reactor Coolant Pressure Boundary

RES	Nuclear Regulatory Research
RG	Regulatory Guide
RIS	Regulatory Issue Summary
SDA	Standard Design Approval
SMR	Small Modular Reactor
SRP	Standard Review Plan
SSC	Structures, Systems, and Components
WPPSS	Washington Public Power Supply System

Appendix E

Identification and Evaluation of Other Hanford Sites

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Contents

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IDENTIFICATION AND EVALUATION OF OTHER SITES AT HANFORD (1.3)

This section documents a comparative analysis of Hanford Site locations, other than the WNP-1 Site, that could be suitable for siting an SMR.

Sites Considered for Evaluation

Locations on the Hanford Site that have existing available infrastructure or have been considered previously for reactor missions were the focus of the evaluation. The Study identified five alternate sites that met these criteria, shown on Figure 1, and listed below:

- WNP-4 reactor site, currently managed by Energy Northwest. This site is near the Columbia Generating Station, an operating, 1,170-megawatt electric power plant. The site has a partially constructed power reactor and associated infrastructure that was constructed in the 1970s but the project was terminated when the plant was about 40% constructed.
- The Hanford 400 Area. This site has two major nuclear facilities: the Fast Flux Test Reactor (FFTF) and the Fuels and Materials Examination Facility (FMEF). FFTF was a liquid metal cooled, 400-megawatt thermal test reactor that operated from 1980 to 1993. The FMEF is a large hot cell facility that was built to support the examination of experiments irradiated in the FFTF but, although fully constructed, was never operated. Both facilities were supported by utilities offices and other buildings, some of which remain today.
- The New Production Reactor Site, a greenfield site that was considered for construction of a new tritium producing reactor in the late 1980s and early 1990s to support the U.S. nuclear weapons program[1]
- A greenfield site near the Hanford 200 East Area that could benefit from 200 Areas infrastructure and previous seismic and other characterization studies
- A greenfield site between FFTF and the Energy Northwest site that potentially could take advantage of past licensing studies that have been performed in this area. The site is also close to existing infrastructure at the 400 Area and Columbia Generating Station.

[1] U.S. DOE, "Draft Environmental Impact Statement for the Siting, Construction, and Operation of New Production Reactor Capacity," U.S. DOE (Washington, DC). DOE/EIS-0144D, April 1991, Vol. 2, Section 3, pp. 3-7-3-31; and Section 5, pp. 5-53-5-54.

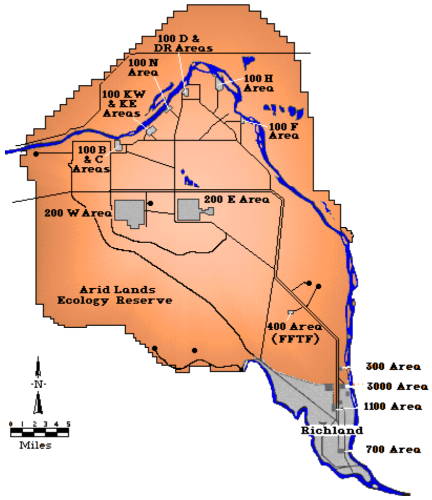

Figure 1. The Hanford Site showing potential alternate SMR sites evaluated.

Evaluation of Potential Sites

The viability of the five sites was first evaluated for consistency with current DOE-RL policy and Site land use planning. In November 1999, the Assistant Secretary of Energy for Environmental Management issued a Record of Decision (ROD) for the Hanford Site's *Comprehensive Land Use Plan Environmental Impact Statement (CLUP)* that defined future uses of the Hanford Site as the cleanup mission ends. For each of the five major geographic areas of the Site, the *CLUP* defines acceptable land uses, using nine land-use designations such as Research and Development or Agricultural.

The designation that allows reactor operations is labeled Industrial.[2] Using the *CLUP*, it was determined that only two of the alternate SMR sites considered were located in areas designated Industrial -- the 400 Area and WNP-4 sites. These sites were further evaluated in comparison to the WNP-1 site.

Hanford 400 Area

An Interim ROD for cleanup of the 400 Area was issued in 2001, calling for several cleanup actions in advance of a final ROD, which has not been issued as yet. As a result, 13 office, maintenance and temporary buildings have been removed. Most of the original infrastructure remains in an inactive state and has not operated for most of the 10 to 20 years, and is shown in Figure 2.

- **Site Assets and Advantages**
  - Most electrical utilities remain including two 115-kV electrical substations, two switchgear stations and the power distribution system
  - Water utilities supporting fire protection and potable water exist
  - Several remaining warehouses would be useful to support an SMR
  - Some security fencing and guard facilities remain

[2] U.S. DOE, "Record of Decision: Hanford :Comprehensive Land-Use Plan Environmental Impact Statement," DOE/EIS-0222, U.S. DOE (Washington, DC), in Federal Register, Vol. 64, No. 218, November 12, 1999, p. 61615-61625; U.S. DOE, "Hanford :Comprehensive Land-Use Plan Environmental Impact Statement, Supplement Analysis," DOE/EIS-0222-SA-01, U.S. DOE (Richland, WA,), June 2008.

  - Much site characterization information such as geotechnical and seismic data exists from the site's construction in the 1970s
- **Site Disadvantages**
  - There are no outgoing power transmission facilities and transmission lines would need to be extended to those supporting the Columbia Generating Station
  - Water supply is currently insufficient to support reactor cooling
  - Groundwater beneath the 400 Area has tritium and nitrates in excess of Environmental Protection Agency standards, jeopardizing its use to fill cooling water needs
  - Much infrastructure would need to be rebuilt, including office, warehouse and maintenance buildings and security systems[3]

Figure 2. Hanford 400 Area with removed structures

WNP-4 Site

Beginning in 1971 and 1972 Washington Public Power Supply System, now Energy Northwest, engaged in design, licensing and construction of three nuclear power plants on land leased from DOE-RL. In 1982 and 1983, construction of two of the plants, WNP-1 and WNP-4 was terminated. WNP-1 was about 70% complete when construction ceased and Energy Northwest, with assistance from the Bonneville Power Administration, has maintained many of the structures and systems is a usable state. Only 40% complete, the WNP-4 utilities, structures and systems were less useful and not maintained as well since termination. The Site is shown in Figure 3.

- **Site Assets and Advantages**
  - Close to the operating plant at Columbia Generating Station
  - Main piping is constructed
  - Fire water with some hydrants and some power distribution is available
  - Water intake facility is constructed and has been well maintained

[3] Washington Closure Hanford, "400 Area Orphan Sites Evaluation Report," OSD-2010-0003, Rev. 0, Richland, WA, November 2010; Washington Closure Hanford, "100 Area/400 Area D4 Project Completion Report," January 1, 2011 , to December 31, 2011, WCH-523, Rev. 0, Richland, WA, February 2012; Washington Closure Hanford, "100 Area/400 Area D4 Project Completion Report," January 1, 2012 , to December 31, 2012, WCH-551, Rev. 0, Richland, WA, February 2013; U.S. Department of Energy, "Segment 5 and 400 Area Interim Remedial Action Report," DOE/RL-2013-34, Rev. 0, Richland, WA, January 2014.

  - o Much of the site characterization studies supporting licensing is complete and current
- **Site Disadvantages**
  - o Site utilities substantially lag those of WNP-1due to termination of construction at 40% completion and less maintenance since the project was terminated
  - o Many of the WNP-4 structures have been and are currently undergoing demolition
  - o Water intake pumps need to be procured and installed[4]
  - o Power vaults are in place but no permanent plant power was installed
  - o The substation supporting the site is inactive and outgoing power transformers were not constructed

Figure 3. Remainder of WNP-4 Site in the foreground with Columbia Generating Station Behind.

Conclusions

Potential alternate sites for construction of an SMR at the Hanford Site have been evaluated for consistency with current land use policies, planning and management by DOE-RL and usefulness in reducing licensing and construction costs. As a result, two viable alternate sites have been identified:

- The Hanford 400 Area, offering existing infrastructure but lacking large water supply, power transmission and fewer existing useful structures
- The WNP-4 Site, offering close proximity to the Columbia Generating Station and current site licensing data but significantly lagging the WNP-1 Site in extent and readiness of utilities, cooling water supply and useful structures.

Although these sites provide a viable backup to the WNP-1 site, licensing and construction of an SMR at these sites will be greater.

[4] Nuclear Regulatory Commission (NRC), "Energy Northwest; Environmental Assessment and Finding of No Significant Impact," NRC (Washington, DC), in Federal Register, Vol, 71, No. 173, September 7, 2006. pp. 52824-52826.

Appendix F

Funding Strategies

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Hanford Site Natural Gas Energy Savings Performance Contracting

Preliminary Assessment

June 2014

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EXECUTIVE SUMMARY

URS, under contract to TRIDEC, chose Johnson Controls to evaluate the ability and benefits of converting the heating fuel used by Steam Plant 242A-BA and the WTP Steam Plant 85 from diesel fuel to natural gas within an Energy Savings Performance Contract (ESPC) project. The goals of this evaluation are as follows:

1. Review of the existing site conditions for the two Diesel Boilers in the 200 Area
2. Develop a high level conceptual design and budget for a solution that would allow DOE Hanford to install a Natural Gas Steam System via a new Central Plant that would utilize the supply of natural gas through a pipeline built by Cascade Natural Gas, through the use of non-appropriated funds.
3. Develop an initial assessment of the total dollar savings associated with the conversion to natural gas that could be realized through the maximum 25 year term of the ESPC project.
4. Provide an initial estimate of the remaining funding available to DOE Hanford, after the costs to install the new central plant that could be utilized to implement additional energy conservation measures (ECM) at the site.

Johnson Controls has developed and implemented two ESPC task orders at the Hanford Site and is currently operating the boiler plants constructed via ESPC in 1997. The savings and project costs within this Preliminary Assessment were developed based on-site visits and best-available estimates of WTP operation schedule during the summer of 2014 by Johnson Controls resources and URS.

ESPC AUTHORIZATION

An ESPC, as authorized by 42 U.S.C 8287, allows federal facilities to contract with an Energy Services Company (ESCO) for the development, design, acquisition, financing, installation, testing, operation, and maintenance and repair of ECMs. ESPC is a firm fixed price contract with a maximum term of 25 years and the entire cost of the ESCO's services must be funded through savings generated by the installed ECMs. Utilization of an ESPC as a means to improve energy and water efficiency, achieve renewable energy goals, and contribute toward sustainability is supported up through the Executive level of the federal government and is cited in President Obama's directive for the federal government to enter into a minimum of $2 Billion in performance-based contracts over the next three years.

Johnson Controls has implemented more federal ESPC task orders than any other ESCO and is listed as a qualified provider on the DOE FEMP ESPC contract and the US Army Corps of Engineers ESPC IDIQ. Our industry experience and presence at Hanford Site will ensure an ESPC solution that promotes safety, security and operational reliability of utilities; aligns with the operational demands of the WTP and other facilities affected by the ESPC; and will contribute toward DOE, RL and ORP sustainability goals.

PROJECT OVERVIEW

This Preliminary Assessment focuses on the construction of a natural gas fired steam plant in the 200 Area of Hanford Site to service the 242-A Evaporator and the WTP. Steam production for each year of the ESPC performance period tracks the anticipated campaign schedule for 242A and the anticipated construction and operation schedule for facilities within the WTP. The savings due to this ECM are significant and will fund other facility upgrades. These other ECMs were grouped together and referred to in the financial model as "Other ECMs Funded by Savings." This category includes: any energy savings deemed appropriate by DOE, which could include a natural gas-fired combined heat and power (CHP) solutions; upgrades to existing HVAC systems at ORP facilities; and Hanford Site-wide electricity distribution system improvements, including right-sized energy efficient transformers, renewable energy solutions, natural gas fueling station for site vehicles, space consolidation, or other important energy initiatives at the Hanford Site.

ECMs Included In the Preliminary Assessment

Descriptions, savings estimates, and price estimates are included in this preliminary assessment for ECM 1.1, Natural Gas Fired Steam Plant and Natural Gas Pipeline. The price estimate was performed by URS using the plant description/schematic design developed by Johnson Controls and was compared to an initial budgetary estimate developed by the onsite Johnson Controls Hanford team.

A brief description of technologies to be evaluated within the other ECMs funded by savings category is provided in Section 12. The price of development, implementation and measurement & verification (M&V) for this ECM category was based on the project size that would allow the ESPC contract to meet the maximum allowable term of 25 years. Savings were assigned to this ECM category based on previous experience in developing ECMs at large DOE facilities, especially the Hanford Site, and site-specific utility rates.

Investment and Savings Summary

The results of the ESPC financial proforma are presented on **Table 1**, ESPC Financial Summary. It is important to note that the simple payback listed on the table is calculated for year 1 of the performance period. During the first year of the performance period, only the Low-Activity Waste (LAW) Facility within WTP will be operational. Savings increase drastically in subsequent years as WTP reaches full operation with the Pretreatment Facility coming fully online in year 9 of the project's performance phase. Due to this fact, the annual savings from years 1-8 are minimal when compared to years 9 to 23. The preliminary cost and saving components have been developed on the following assumptions:

1. DOE nuclear safety requirements prohibit the installation of natural gas lines within an approximate 0.625 mile distance of any nuclear facility. The longer the distance, the higher the initial installation costs are for the aboveground steam and condensate return lines needed to supply the 242-A Evaporator and WTP facilities.
2. The existing DOE timeline calls for Natural Gas to be supplied to the 200 Area by FY 2019. The natural gas will be supplied by a pipeline built by Cascade Natural Gas through a contract that is outside of the ESPC. The preliminary assessment does not include the costs to build a pipeline.
3. The new central steam plant will be operated and maintained by the selected ESCO through the savings generated by the ESPC project.
4. As detailed in the following Table 1, the estimated cost to build this new Central Steam Plant and its applicable steam system piping is **$120,654,122**.
5. As detailed in the following Table 1, the estimated additional funding to use to implement other ECMs at the Hanford Site is **$68,509,537**. This value is based on a two-year construction duration and a 23-year performance period. This is also based on the high-activity waste and pretreatment facilities at WTP coming online at year 9 of the 25-year term.
6. Note that if the DOE nuclear safety requirement for a buffer distance for a natural gas pipeline is waived/changed, thus allowing the new pipeline to be brought directly to the two existing diesel steam plants at 242-A and the WTP, the project's parameters change to the following:
    a. Cost to convert the existing diesel boilers to a dual fuel diesel/natural gas steam boiler system: **~$10-15M**
    b. Estimated additional funding to implement other ECMs at the Hanford Site: **~$170M**

A detailed breakdown of these ESPC cost, savings, and year by year financial performance is provided in the price proposal section of this preliminary assessment.

Table 1. ESPC Financial Summary

ECM No.	Equipment Description - Title	Implementation Price	Annual Cost Savings	Simple Payback (Years)
19.1	ESPC Proposal Development	$3,146,997		
1.1	Natural Gas Fired Steam Plant and Natural Gas Pipeline	$104,394,637	$1,192,787	87.52
	Funding Available for Other ECM Development	$68,509,537		
	ESPC Project Direct Costs (Less Project Development)	$13,112,488		
	Total	$189,163,659	$1,192,787	158.59

Note: Energy savings and cost savings appearing in this schedule represent year 1 of the performance period. Savings increase significantly later in the performance period as the throughput of the waste treatment plant increases. The increase in annual savings is portrayed on Table 8, Schedule TO-1.

Measurement and Verification

Standardized methods used by Johnson Controls for conducting measurement and verification (M&V) are a cumulative result of numerous years of performance contracting experience. The methods being used for this project conform to those outlined in the document published by the FEMP entitled "M&V Guideline for Federal Energy Projects," Version 3.0. Wherever feasible, metered utility data and fuel purchase records will be used to validate ECM performance.

Project Development and Implementation Schedule

Table 2 provides an estimated ESPC development schedule, which allows for the new boiler plant to be constructed, commissioned, and brought online concurrent with anticipated functional startup of the primary facilities within the WTP that matches the estimated timeline for the completion of the natural gas pipeline (FY 2019).

Table 2. . Project Development and Implementation Schedule

Milestone/Activity	Completion Date
TRIDEC Report Delivered	8/7/2014
DOE Hanford ESCO Selection Process Started	Spring 2015
DOE ESCO Selection Process Complete	Fall 2015
ESPC Design Process (~12 Months)	Fall 2016
ESPC Awarded	Fall 2016
Start of ESPC Implementation Phase (Construction)	Winter 2017
ESPC Project Complete and Accepted by DOE (two year duration)	Winter 2019
23 Year Performance Period	2019-2042

Summary

The recommended ECMs in this preliminary assessment will drastically impact the Hanford Site's overall progress towards DOE energy and sustainability goals. In addition, the work will improve utility system reliability and considerably reduce the cost of steam production.

ECM 1.1: NATURAL GAS-FIRED STEAM PLANT AND NATURAL GAS PIPELINE

1. IDENTIFICATION OF THE ENERGY CONSERVATION MEASURE

Location: Richland, Washington
Federal Agency/Site: U.S. Department of Energy – Hanford Site
Primary Site Contact: DJ Ortiz
Telephone Number: 509-376-0950

This ECM uses natural gas brought across the Columbia River to the 200 Area of the Hanford Site and constructs a natural gas-fired steam plant to serve the 242-A Evaporator and WTP. In addition to providing significant fuel cost savings, ECM 1.1 delivers energy security and steam surety by keeping the existing diesel fuel-fired boiler plants operational in standby mode.

1.1 EXISTING CONDITIONS

Process steam is provided to the 242-A Evaporator by a diesel fuel-fired steam plant constructed as part of the 1997 ESPC, referred to as 242A-BA. The plant contains two 700 HP low-pressure steam boilers and one 200 HP high pressure steam boiler. The high pressure and low pressure steam is distributed in separate loops. The plant has a 40,000-gal diesel fuel tank. Boiler operation is dictated by the campaign schedule for the 242-A Evaporator. Traditionally, the campaigns run for six months per year with the boilers down for the other six months. However, the runtime for the campaigns is scheduled to increase significantly with a potential for 11 months of runtime and one month down per year.

There is no boiler or deaerator redundancy in Plant 242A-BA. Boiler reliability and efficient operation has been a product of the Johnson Controls operating and maintenance contract provided within the original ESPC. The operating contract expires in FY 2021. Steam production is not metered. Diesel fuel use is logged and the diesel fuel use per evaporator campaign is monitored.

Plant 85 was constructed ten years ago to supply high pressure steam (135 psig) to the facilities that make up the WTP for building heat and process requirements. Plant 85 consists of six 1,200 HP diesel fueled fire tube boilers with stack economizers. Each boiler has a rated steam production capacity of 41,400 lbs per hour and it is expected that five boilers will be required to meet the operating load of the WTP with one boiler remaining in hot standby.

Diesel fuel for Plant 85 is stored in a 275,000-gal tank. The tank contains enough fuel to operate the plant for one week. Six tractor trailer deliveries of fuel oil are required per day to meet boiler plant demand.

1.2 PROPOSED UPGRADES

ECM 1.1 will significantly reduce the cost of steam production and provide boiler fuel redundancy for the 242-A Evaporator and WTP. Natural gas will be delivered to Hanford Site by Cascade Natural Gas Corporation through a new pipeline. The 12” pipeline will run from the Williams Northwest Pipeline interconnect in Pasco, WA to the 300 Area, capable of supplying 1,600 dekatherms of natural gas per hour at a pressure of 125 psig. The pipeline will cross the Columbia River, using directional boring to minimize the chance of negative environmental impact.

Once the natural gas enters Hanford Site, it will be run underground along Route 4S to an open area adjacent to the WTP. The new natural gas-fired steam plant will be located outside of the fence surrounding the WTP approximately 3,300 ft from GPF Way in the currently open field. The steel building plant structure will have an open floor area of 16,500 sf. Ten 1,000 HP natural gas-fired, fire tube boilers, capable of producing steam at 250 psig, will provide sufficient steam to meet the concurrent demand of the 242-A Evaporator and WTP. Each of the boilers will have stack economizers to maximize operating efficiency. The plant will have its own dedicated deaerator system, condensate receiver, water softener, chemical treatment, and will employ surface blowdown heat recovery.

The new steam plant will be connected to the 242-A Evaporator and WTP steam distribution systems via aboveground insulated steam piping and insulated condensate return piping. The plant will be tied to WTP Plant 85 deionized water supply, potable water supply, process sewer, electrical supply, and communication systems. A natural gas-fired backup generator, sized to meet the electrical load of the new plant, will be located at the new steam plant.

The new steam plant will be operated and maintained throughout the ESPC performance period by Johnson Controls and will be the primary steam source for the 242-A Evaporator and WTP. Plants 242A-BA and 85 will operate in hot standby when the process campaigns are run. This operating approach will provide complete redundancy for the steam supply. This new steam plant could also have the capability to provide steam service to future DOE facilities in the 200 Area, but at this time, all of the cost information has been developed to only service the 242-A Evaporator and WTP.

2. Baseline and Post-Installation Energy Use and Cost

The proposed annual energy and cost savings are presented in **Table 3 and Table 4**.

Table 3. Baseline and Post-Installation Energy Use

	Electricity Use (kWh/Yr)	Natural Gas (MBtu/Yr)	Diesel Fuel (MBtu/Yr)	Total Energy (MBtu/Yr)
Baseline	0	0	104,057	-52,525
Post-Installation	2,683,200	104,057	43,368	136,238
Savings	-2,683,200	-104,057	60,690	69,232

Note: Savings represent year 1 of the performance period as the waste treatment plant begins partial operation.

Table 4. Baseline and Post-Installation Energy Cost

	Electricity Use ($/Yr)	Natural Gas ($/Yr)	Diesel Fuel ($/Yr)	Total Energy $/Yr)
Baseline	$0	$0	$3,533,980	$3,533,980
Post-Installation	$103,037	$765,310	$1,472,846	$2,341,193
Savings	-$103,037	-$765,310	$2,061,134	$1,192,787

Note: Utility unit costs are for Year 1 of the Performance Period (FY 2019).

Notes for Tables 3 and 4:
1. MBtu = 1,000,000 Btu
2. Energy values: 0.003413 MBtu/kWh of Electricity and 0.1305 MBtu/Gallon of Diesel Fuel

2.1 Assumptions for Current Operating Conditions

The following assumptions are made regarding current operating conditions:

- Boiler combustion efficiency is 85%
- Boiler average fuel to steam efficiency is 80.8%
- FY 2014 electricity unit cost is $0.032 per kWh
- FY 2014 fuel oil unit cost is $3.62 per gallon
- FY 2014 natural gas unit cost is $5.60 per MBtu
- Average annual electricity escalation rate is 3.71%
- Average annual diesel fuel escalation rate is 4.13%
- Average annual natural gas escalation rate is 5.60%
- Average service and materials escalation rate is 2.94%
- 242A-BA diesel fuel use per cold run is 30,000 gal

- 242A-BA diesel fuel use per gallon of waste processed is 0.163778 gallons per gallon
- 242A-BA auxiliary electricity use per campaign is 180 kW
- 242A-BA lights and equipment electricity use is 40 kW
- 85 auxiliary electricity use per campaign is 100 kW per boiler
- 85 lights and equipment electricity use is 80 kW

2.2 Assumptions for Proposed Operating Conditions

The following assumptions are made regarding proposed operating conditions:

- Natural gas boiler combustion efficiency is 85%
- Natural gas boiler average fuel to steam efficiency is 80.8%
- Diesel boiler load during hot standby is 5% of boiler capacity
- Diesel boiler average fuel to steam efficiency during hot standby is 66.5%
- 242-A Evaporator campaign schedule provided by the Hanford Site in FY 2010 was delayed by 2 years to reflect current operating projections
- LAW Facility startup begins FY 2019 with full operation beginning in FY 2023
- LAW comfort steam load is 15,700 lbs per hour and process load is 3,100 lbs per hour
- HLW Facility startup begins FY 2023 with full operation beginning in FY2027
- HLW comfort steam load is 20,000 lbs per hour and process load is 4,000 lbs per hour
- Pretreatment Facility startup begins FY 2027 with full operation beginning in FY 2029
- Pretreatment comfort steam load is 40,000 lbs per hour and process load is 110,000 lbs per hour
- Once each facility is fully operational, the process steam load factor is 70%
- Balance of facilities steam load is 10,350 lbs per hour
- Steam distribution loss is 2,070 lbs per hour

2.3 Energy Savings Calculations

The baseline energy consumption and post-installation energy consumption were estimated using Tables 8 through 11.

3. Location Affected

Natural gas piping will run below the Columbia River to the 300 Area of Hanford Site. Underground piping will be installed along Route 4S to deliver natural gas to the new natural gas-fired steam plant. The new steam plant will be located in the open field adjacent to the WTP. Aboveground steam and utility lines will tie the new steam plant to the WTP and the steam and condensate lines servicing the 242-A Evaporator. No changes to process operations within the 242-A Evaporator or WTP will be required for ECM implementation.

4. Interface with Government Equipment

ECM 1.1 will interface with existing steam distribution, condensate return, deionized water supply, potable water supply, process sewer, electrical and communication systems. Plants 242A-BA and 85 will be placed in hot standby mode.

5. Proposed Equipment Identification

Equipment will be specified during the investment grade audit (IGA) as part of the engineering analysis and design. Cut sheets and specifications will be provided at that time. For the purpose of this Preliminary Assessment, the equipment in **Table 5** was included in the price estimate in addition to the natural gas pipeline.

Table 5. Proposed Equipment

Item / Description	Quantity
Plant Building and Major Equipment	
Steel Building - 110'x 150' x 40' (16,500 sq./ft.)	1
Cleaver Brooks CBEX Natural Gas Fired Steam Boilers - 250 psi / 1,000 HP	10
Stack Economizers	10
Stacks	10
Surface Blowdown Heat Recovery	1
Deaerator Pumps and Controls	1
Deaerator Tank and Stand (350,000 PPH each)	2
Condensate Receiver - 30,000 Gallons	1
Water Softener (175 GPM / 1,000,000 grain)	3
Chemical Treatment	1
Pressure Reducing Valve	
242A (175/100) 4"	1
242A (175/15) 12"	1
WTP (175/135) 16"	1
242A-BA (175/10) 4"	1
Relief Valve Assembly	
242A - 100 psi	1
242A - 15 psi	1
WTP - 135 psi	1
Distribution System and Utilities	
250 class Stop Valve - 16"	11
250 Class Stop Valve - 12"	17
250 Class Non-Return Valve - 12" (Swing-Check)	10
Insulated Condensate Return Pipe - 4" x ft.	9,000
Insulated Steam Pipe - 12"x ft.	9,000
Insulated Steam Pipe - 16"x ft.	5,281
Insulated Condensate Return Pipe - 8" x ft.	5,281
Heat Trace x ft.	14,781
Potable Water Pipe - 8"x ft.	5,281
Deionized Water Pipe - 8"x ft.	5,281
Process Sewer 8" x ft.	5,281
Electrical Line (Conduit & Wire)	5,281
Communication Line (Conduit & Wire)	5,281
Pipe Supports	952
Muffler/Silencer	1
Back-up Generator / Transformer / Switchgear	1
Transformer (13.8/480V - 500 kVA)	1
Natural Gas Train	1

6. Physical Changes

Physical changes within existing facilities will not be required. Utility and piping tie-ins will occur in existing steam plants or along existing distribution systems outside of the existing facilities.

7. Utility Interruptions

For planned utility service interruptions, Johnson Controls will furnish a request to Hanford Site for approval 15 working days in advance. The request will identify the affected areas and the duration of the planned outage. Whenever possible, utilities will be returned to normal service by the end of the normal working day. However, should service interruptions be required that exceeds eight hours, Johnson Controls and Hanford Site will plan for appropriate shutdowns and will make arrangements with Hanford Site personnel.

Utility interruptions will be required for interconnection of new steam plant to the existing steam distribution system. However, work will be scheduled when plants 242A-BA and 85 are down to minimize impact.

Hanford Site will test, operate and potentially repair or replace failed steam isolation valves for implementation of this ECM. Failed isolation valves would lead to increased short term localized interruptions of steam.

8. Government Support Required

Hanford Site support will be required to ensure access to the facility. Johnson Controls will coordinate access for specific buildings 14 days in advance. For planned utility interruptions, Johnson Controls will request approval from Hanford Site 15 working days in advance. The request will identify the specific areas affected and the duration of the planned outage. The Hanford Site and Johnson Controls will coordinate efforts to accommodate reasonable variations in daily work schedules.

Johnson Controls will coordinate with Hanford Site for the issuance of photo contractor badges and required contractor training.

The Hanford Site will provide the following support:

- Timely repair or replacement of existing code concerns and defective equipment not included but having an effect on the performance of this ECM
- Operation, isolation, lock out/tag out, etc. of utilities and equipment needed to support the construction of this ECM
- Adequate space onsite for material storage trailers.
- Hazardous material abatement, such as asbestos and lead

9. Environmental Impact

This ECM will have a positive environmental impact through resource conservation and pollution prevention as follows:

- Reduction in diesel fuel use and associated greenhouse gases
- Reduction in truck traffic associated with diesel fuel delivery
- Johnson Controls and its subcontractors will minimize waste production and maximize recycling during the implementation of this ECM

10. Rebates and Incentives

No utility rebates or financial incentives are applied to ECM 1.1.

11. Schedule

The following are the project milestones for this ECM. The schedule for the entire project is presented at the beginning of the ECM Descriptions and Energy Savings section.

Task	**Duration**
Engineering/design acceptance	120 days
Equipment procurement/lead time	90 days
Installation and commissioning	420 days

12. OTHER ECMs FUNDED BY SAVINGS

Implementing cost effective ECMs at Hanford Site can be challenging due to the very low cost of electricity provided by Bonneville Power Authority (BPA) and the cost of implementing work in a secure federal facility. In the case of this ESPC opportunity, the cost savings by converting the primary steam generating fuel from diesel fuel to natural gas is large enough to fund a significant number of energy efficiency and sustainability projects. Using of this ESPC will allow the Hanford Site and DOE to make significant strides toward their federally mandated energy use reduction, renewable energy, and sustainability goals. Johnson Controls suggests that the following ECMs be evaluated within the IGA for implementation within the ESPC.

12.1 NATURAL GAS FIRED COMBINED HEAT AND POWER

Combined heat and power solutions, also referred to as cogeneration, can take many forms. One popular configuration includes the use of a steam turbine fed by high pressure steam boilers to produce electricity prior to distribution of low pressure steam to facilities for heating and process use. Another reliable configuration utilizes a gas fired turbine electrical generator with waste heat used to produce steam for distribution to facilities. Often, the gas turbine solution includes a heat recovery steam generator and duct burner to maximize useable steam produced concurrent with electricity generation.

The two primary drivers in making combined heat and power cost effective is the utilization of all electricity and steam produced and maximizing spark spread (the difference between the unit cost for electricity and the cost of the source fuels for the cogeneration unit). Utilization of all energy produced can be addressed by sizing the equipment to meet the base concurrent heating and electrical load or to utilize equipment such as absorption chillers to produce cooling using the steam during the summer. Spark spread will assist in determining the combined heat and power technology based on the thermal ratio for equipment and source fuel selection, which may include renewable resources.

It may be feasible to utilize gas turbine generators in place of one or more boilers being considered for the new natural gas fired steam plant. There may be opportunities for combined heat and power solutions in other areas of Hanford Site. Small solutions, such as the use of microsteam turbines as a replacement for pressure reducing stations in facilities, may prove technically feasible.

12.2 SITE WIDE ELECTRICITY DISTRIBUTION SYSTEM IMPROVEMENTS

Hanford Site electrical transmission and distribution services Hanford Site and other businesses and communities with 2 million kWh or electricity. In addition, the expected electrical demand for WTP is 70 MW. Small reductions in distribution system losses will provide significant energy savings opportunities. A comprehensive model of the distribution system will indicate the potential for the replacement of transformers with right-sized energy efficient technologies, switchgear upgrades, power factor correction, and overall system balancing to reduce losses. The model may serve as the basis of a smart, secure micro-grid to utilize on-site generation to meet critical loads in the event of a utility supply outage.

12.3 RENEWABLE ENERGY SOLUTIONS

The mid-Columbia region has an abundance of agricultural waste biomass (7.5 million tons per year of wheat straw) that could be used to fuel biomass combined heat and power solutions. In addition, solar resources are adequate for solar thermal, concentrated solar generation or photovoltaic consideration.

12.4 ORP BUILDING EQUIPMENT AND OPERATIONAL EFFICIENCY IMPROVEMENTS

Traditional facility energy efficiency improvements not only reduce facility energy use from 15% to 50%, but also reduce the size of central plant equipment and renewable energy resources needed to provide utilities to the facilities. Upgrades to building envelope, lighting systems, HVAC systems, controls, motors, and process equipment would be considered, as well as, the resultant opportunities in central heating and chiller plants and utility distribution piping systems.

12.5 NATURAL GAS FUELING STATION

Natural gas fueled vans, buses, heavy machinery and construction equipment have reached the point of commercial acceptance. Construction of a natural gas fueling station located in either or both the 200 or 300 Areas would provide the fueling infrastructure needed for DOE to phase out their diesel fuel vehicles and replace them with modern natural gas vehicles.

12.6 SPACE CONSOLIDATION (NEW BUILDING TO REPLACE TRAILERS)

Utilization of ESPC to improve energy efficiency of facilities and reliability of utility systems often provides an opportunity for space consolidation. Relocating employees to facilities with the most modern infrastructure and energy efficient systems provides the opportunity to shut down inefficient facilities. LEED accreditation can be included as part of the energy efficiency effort and included in the ESPC.

13. MEASUREMENT & VERIFICATION OVERVIEW

The M&V methodology to be employed is consistent with the FEMP document titled *M&V Guidelines: Measurement and Verification for Federal Energy Projects, Version 3.0*. The specific M&V approach for each ECM is influenced by the availability of site utility data, utility billing histories, sub-metered utility data and the amount of savings projected. The M&V approach defined in the Investment Grade Audit will be developed by and constitute agreement between Hanford Site and Johnson Controls. Hanford Site personnel involvement and witnessing of measurements is encouraged throughout the M&V effort.

There are two components to the Johnson Controls overall M&V approach, which are consistent with the FEMP M&V Guidelines.

The first component demonstrates energy savings potential by confirming the accuracy of the Baseline conditions defined during the Investment Grade Audit and demonstrating that ECMs are capable of generating the predicted savings. The confirmation of each ECM will include, but is not limited to, inspections, instantaneous measurements, short-term trending and Commissioning activities. These findings will be reported in detail in the Post-Installation Report.

The second component is the measurement of energy savings throughout the Performance Period. The approach and rigor of Performance Period M&V for each ECM is based on projected savings, interaction with other ECMs, cost of the M&V procedure, and other considerations identified by Hanford Site and Johnson Controls during the Investment Grade Audit. The M&V approach chosen will ensure that performance data is measured, analyzed, and presented accurately in each Annual Report for Hanford Site review.

13.1 PROPOSED SITE SPECIFIC M&V APPROACH

This M&V approach discussed herein represents a starting point for the detailed development of an M&V Plan that satisfies Hanford Site requirements. FEMP M&V Option B will validate the savings for ECM 1.1, Natural Gas Fired Steam Plant and Natural Gas Pipeline.

A great deal of historical operating data has been collected over the past decade for Plant 242A-BA. Fuel oil use is tracked and correlated back to Evaporator Building campaigns. The fuel oil use per campaign was extrapolated to each year in the performance period to estimate the fuel oil use and to estimate the steam that would be required from the new natural gas fired steam plant.

Comfort loads and process loads for each of the WTP facilities. A load factor of 70% was applied to the process steam requirement for each of the WTP facilities once they reach full operating status. The facility loads were used to calculate baseline diesel fuel use and the amount of steam that would be required from the new natural gas fired steam plant.

Given that the baseline diesel fuel use for plants 242A-BA and 85 are driven by their connected facility operating schedules, the ESPC baselines will continue to evolve as the operating schedules are finalized by Hanford Site up until submission of the Investment Grade Audit.

Following construction, the natural gas fired steam plant will undergo an extensive commissioning and performance testing process. The plant will operate for 30 days during which time natural gas use, steam production and condensate return will be trended to validate the potential of the plant to meet or exceed the ESPC guaranteed savings. The result of the testing will be provided in the Post-Installation Report.

The natural gas fired steam plant will continually meter and trend natural gas consumption, steam production and condensate return quantities. This data will provide boiler plant performance validation in near real-time. The boiler plant control system will include diagnostics and alarm points to alert the operator of potential performance issues. Should performance fall outside of acceptable range, operational efficiency of the installed equipment will be measured. In addition to reporting performance of the new steam plant, equipment inspection reports and service records summaries will be included in the Annual Reports.

Either FEMP Option A or B will be used for the balance of the ECMs implemented depending on the magnitude of savings, complexity of the ECM and available metered data. The M&V approach will be determined as the ECM feasibility is investigated.

13.2 Utility Rates

Utility rates will be validated and agreed upon by Hanford Site and Johnson Controls during in the Investment Grade Audit. The utility rates will be applied to the verified energy savings with mutually agreed upon annual escalation rates.

13.3 Electricity

Electricity to the Hanford site is provided by the BPA. BPA is able to provide Hanford and other Federal Government customers with electricity at rates well below the market rate. The Baseline electric rate used in the development of the Preliminary Assessment is $0.032 per kWh.

13.4 Diesel Fuel

Plant 242A-BA and 85 operate using No. 2 diesel fuel oil delivered via tanker trucks. The round trip distance from the Richland City limits to the boiler annex is approximately 60 miles and requires extensive security measures for site entry. The delivered cost for this fuel used in the Preliminary Assessment is $3.62 per gallon.

13.5 Natural Gas

Natural gas would be delivered to the new natural gas fired steam plant by Cascade Natural Gas Corporation. The unit cost for natural gas used in the Preliminary Assessment is $5.60 per MBtu.

13.6 Water Rates

Hanford Site pumps water directly from the Columbia river using pumps operated by RL and does not pay a for the water. The cost of electricity for pumping the water is less than $0.50 per kGallon. Given that this ESPC will have very little effect on water consumption and the cost of water is so low, water was excluded from the Preliminary Assessment.

13.7 Sewage Treatment Rates

There are no applicable sewage treatment rates for Hanford Site. All potable water waste is sent to the onsite drain fields.

14. ECM COMMISSIONING APPROACH

14.1 INTRODUCTION TO COMMISSIONING

Commissioning is a process for achieving, verifying, and documenting the performance of building systems. System Commissioning ensures that the design intent for building modifications is met, as are the operational needs of the systems. Commissioning extends through all phases of the project, from conceptual design to post-construction operation, with checks at each stage to ensure procedures are followed. This approach creates a process to verify and document the performance of building systems on data forms included in the design documents, construction documents, O&M manuals, and specific Commissioning Reports, as appropriate. Post-Acceptance documentation is included in the Annual Report.

The Commissioning Team consists of the Johnson Controls Project Manager, Johnson Controls Commissioning Authority or Commissioning subcontractor hired by Johnson Controls, Hanford Site Contracting Officer's Technical Representative or designee, Architectural/Engineer design sub-consultant, construction subcontractors, and equipment suppliers. If appropriate, specific Hanford Site building or facility managers may also be part of the Commissioning Team.

The Commissioning Authority duties include oversight and implementation of the Commissioning Plan and related procedures and policies. Duties include the coordination, implementation, and documentation of the Commissioning activities ensuring the process is performed in a timely and competent manner.

Johnson Controls is committed to providing Hanford Site with a complete and effective Commissioning program. Our corporate mission is that of continually exceeding our customers increasing expectations. This is achieved in part, through continuous improvements in quality and service. Through mentoring, training, and the utilization of proper testing and inspections, a quality product is assured. Inspections, testing, and system Commissioning are performed at the required Project Phase according to established procedures. Subcontractors are completely aware of the requirements and are actively involved with the Commissioning process assuring a timely and quality installation. Installations performed either by subcontractor or self-installation are subject to the same rigorous validation processes.

The Commissioning Plan, submitted after approval of the ECM Design and Construction Package, provides a formal Commissioning program to ensure implementation and performance meets or exceeds levels specified in the Investment Grade Audit / Final Proposal and that contract requirements are met. The Commissioning Plan includes team member roles and responsibilities, the Commissioning schedule, descriptions of specific Commissioning steps and requirements, and sample performance and function verification forms.

The following sections provide a brief introduction to the Commissioning process.

14.2 PROGRAM PHASE COMMISSIONING

During the Program Phase Hanford Site operational requirements are outlined, energy requirements calculated, construction cost budgeted, and the Project Management Plan is developed. Emphasis is placed on documenting the facility Baseline, proposed operation, energy savings calculations, pricing, and schedule. The primary deliverables of the Program Phase Commissioning process are the Final Proposal, Design and Construction Package, and Commissioning Plan. The design intent of each ECM is defined in the Final Proposal. The Design and Construction Package contains the quality control plan, site safety plan, equipment submittals, and schematic design drawings. The Design and Construction Package emphasizes the design intent defined in the Final Proposal. The Commissioning Plan is a working document and evolves as the project moves through design and construction. The initial Commissioning Plan is delivered immediately following the design and construction submittal subsequent to Task Order award.

14.3 Detailed Design Phase Commissioning

The objective of the Commissioning process during the Design Phase is to review and document the design as the project evolves. Documentation ensures that the design intent is met when the final drawings, specifications and contract documents are prepared. The Commissioning Plan for the Construction Phase and Acceptance Phase is prepared during the Design Phase.

The Design Specification is a dynamic document and is modified as the design process progresses. Each modification is marked with a revision number, revision date, and a description of the modification provided on a master revision list. The Commissioning Authority approves each revision. At various phases during the design, the Commissioning Authority performs a review of design submittals. A report of each review is maintained detailing review comments and resolution of issues, as appropriate. Any deviation in the design documents from the Design Specification is evaluated and results in either a modification to the Design Specification or a correction to the design documents.

Verification (pre-functional and functional performance testing) procedures are prepared describing the extent of verification testing required during construction and acceptance. The verification procedures clearly state the requirements of what to test, test methods to be used, under which conditions to test, and criteria for acceptance. The verification procedures describe start-up, pre-functional checklists, manual performance tests, system trending, or stand-alone data logging, as appropriate.

14.4 Construction Phase Commissioning

The Construction Phase typically starts with selection and contracting of equipment vendors and installation subcontractors in accordance with the bid and contract documents prepared during the Design Phase. The objective of the Construction Phase is to review and document the implementation of the ECMs. The documentation ensures that the design intent is met when the installation is complete. At the end of the Construction Phase, the ECMs are ready for functional performance testing. The Commissioning Plan for the Acceptance Phase is further developed during the Construction Phase.

Submission of documentation describing equipment to be installed is reviewed by the Commissioning Authority to ensure compliance with the Final Design documents. Equipment submittals include performance data such as efficiency, capacity, flow rates, velocity, pressure losses, horsepower, rpm, electrical data, system level sequence of operation data, etc. Where appropriate, performance data is provided for full- and part-load conditions covering the entire operating range for the equipment. Shop drawings, test procedures, report forms, data sheets, and checklists to be used in the pre-functional performance tests are also provided. A report of each submittal review is maintained detailing review comments and resolution of issues. Any deviation in the submittals from the design documents is evaluated and results in either a refusal of the submittal or an explanation for acceptance of the submittal with reasons for differences from the design documents. During the construction process, quality assurance and safety inspections occur in accordance with the accepted plans. Documentation of the inspections, problems observed and corrective action are maintained.

Prior to formal functional performance testing, systems are installed, pre-start checklists are completed, equipment is started, and initial operational checks are made. In the case of control systems, all control devices are adjusted and calibrated. For large mechanical retrofit projects, air and fluid test, adjustment, and balance is usually completed. The checklists and pre-functional performance test data are recorded and maintained along with a descriptive narrative of the testing methods used. Any deviations from the submittal data are noted and corrected, if necessary.

14.5 Acceptance Phase Commissioning

Acceptance Phase procedures ensure that building systems affected by ECMs are operating in accordance with the design intent and are producing the energy savings guaranteed in the Final Proposal. Therefore, many of the tasks performed during Acceptance Phase Commissioning are executed in tandem with the Post-Installation M&V for the project. As-built documentation and functional equipment testing are the primary components of Acceptance Phase Commissioning. The Commissioning Plan for Post-Acceptance Commissioning is developed during the Acceptance Phase.

Typically, functional performance testing is accomplished by manual testing (changing a setpoint and observing a response), instantaneous measurement using a portable meter, short-term measurement using portable data loggers, or through the trending capability of a control system. The focus of functional performance testing for Acceptance Phase Commissioning is to observe equipment or system operation at various operating conditions. Depending on the type of ECM, the length of the observation period varies. Hanford Site is encouraged to witness the functional testing.

Functional performance testing follows from the pre-functional testing completed at the end of the Construction Phase. The objective of functional performance testing is to demonstrate that the equipment is operating efficiently and according to design intent under a variety of conditions. The testing plan for each piece of equipment or system includes equipment description, purpose of the test, specific parameters to be tested, tools or instruments required, design data pertinent to the test, sequence of operation or setpoint data, scheduling requirements, special instructions or warnings, sampling strategies (if appropriate), and expected results. If the piece of equipment or system failed to meet expected results, the deficiency is evaluated. The cause of the deficiency is determined and documented as non-compliant. If the deficiency is due to the implementation of the ECM, then corrective actions are performed and documented, as appropriate, and the functional performance test is repeated. If equipment or activities outside of the scope of the ECM caused the deficiency, then the deficiency and cause are documented but not corrected. Documentation following the functional performance test includes the name of the person performing the test, names of witnesses to the test, date and time of the test, conditions of the test, and results of the test.

Final as-built drawings are prepared during the Acceptance Phase. The as-built drawings document equipment installed during the Construction Phase and any modifications to the Final Design drawings required for construction. Any substitutions, compromises or variances between the Final Design documents and as-built drawings are explained. O&M Manuals are prepared and submitted during the Acceptance Phase. The manuals may be edited based on the results of the functional performance tests. The O&M manuals typically include descriptions of equipment and systems, hands on operation of the equipment, equipment start-up procedures, emergency procedures, adjustment tolerances, maintenance schedules, warranties, recommended spare parts inventories, troubleshooting guides, health and safety concerns, relevant Commissioning Report documents, etc. Facility staff training is also completed in accordance with the description provided in the Management Approach section of the Investment Grade Audit / Final Proposal.

14.6 Post-Acceptance (Continuous) Commissioning

Post-Acceptance Commissioning, also referred to as Continuous Commissioning, is the continued adjustment, optimization, and modification of equipment or building systems to meet changing facility requirements. As use and function of a facility change, building systems must be adapted to efficiently meet the changing occupancy and/or facility utilization. This may include updating documentation to reflect minor setpoint adjustments, system maintenance and re-calibration, major system or equipment modifications, and/or ongoing training of maintenance personnel. The extent of continuous Commissioning required is determined by the scope of modifications and occupancy changes that are to be made in the facility.

14.7 Commissioning Documentation

In each stage of project commissioning, documentation is compiled as described in the Commissioning Plan. The final Commissioning Report consists of sections for each phase of the Commissioning process. In addition, Johnson Controls maintains a document control log starting at contract award. Each outgoing piece of correspondence or submittal relating to the Commissioning effort has a unique identification number and is listed in the document control log. The log is included as part of the Commissioning Report. The commissioning report is provided to Hanford Site as part of the Post-Installation Report.

15. MANAGEMENT APPROACH

15.1 ORGANIZATION

15.1.1 SITE MANAGEMENT PLAN

A Johnson Controls team of experienced professionals with on-site knowledge of Hanford Site will lead the development, implementation, and management of this ESPC project. Our team's security clearances or existing Hanford Site contractor badges, combined with previous experience working on-site, will reduce mobilization time and maximize team efficiency on-site.

The following individuals make up the Johnson Controls Hanford Site team:

Ben Tsu*	Hanford Site Account Manager
Steven Smith*	Federal Director of Engineering
Mike Parker*	Strategic Offerings Engineering Manager
Patrick Weiher*	Hanford Site ESPC Program Manager
TBD	Hanford Site Project Manager
Joe Burrell*	Hanford Site Operations Manager

*Also worked on the previous ESPC project at Hanford Site

15.1.1.1 Project Management Responsibilities

The Project Manager, supported by the Federal Operations team, is responsible for the implementation of the proposed ECMs. The Project Manager has authority concerning the approval, allocation, and control of resources, including contractors assigned to the project, as well as direction of work assignments.

15.1.1.2 Project Schedule

The project schedule for design and implementation is developed during the IGA. The three levels of schedules include: Installation Project Schedule, ECM Schedules, and Task Detailed Schedules.

The Installation Project Schedule shows project tasks and milestones. It includes contract requirements and the major activities necessary to support them. The Installation Project Schedule provides detail for each ECM and verifies the feasibility of the Installation Project Schedule. A Task Detailed Schedule is prepared for each subcontractor that supports ECM Schedule requirements and shows activities and milestones for subcontractors.

15.1.1.3 Cost Control

Johnson Controls bears the cost risk in fixed-price performance contracts. We control the ECM investment costs so they do not exceed their recovery through guaranteed annual savings. Effective control depends on an accurate budget plan, frequent monitoring of costs, and rapid response to potential cost concerns.

15.1.1.4 Total Project Control

The Project Manager monitors the schedule, technical status, and predictions of future cost. Whenever schedule, cost, or technical projections indicate a developing problem, they are acted upon. Schedules are reviewed daily, and predictions of milestone completion are recorded. Technical performance is verified through physical inspection and measurement of energy savings. If unsatisfactory performance is encountered, reports are prepared indicating the nature of the problem and corrective actions .The Project

Manager holds Job Progress Meetings on a regularly scheduled basis to review project status and direct appropriate actions providing a forum for participants (Hanford Site, Johnson Controls and subcontractors) to resolve issues.

15.2 SUBCONTRACTING

15.2.1 Identifying Qualified Subcontractors

Johnson Controls actively pursues qualified subcontractors. The Project Manager is responsible for this outreach, information-gathering, and database-maintenance activity. We maintain a list of qualified contractors that have the capability to perform project-related tasks in the Pacific Northwest. Prospective subcontractors are selected for inclusion on the list based upon the quality of their work, personnel, timeliness of delivery, safety records, and financial strength. Our database includes the contractors and vendors utilized to successfully implement the previous ESPC at Hanford Site.

15.2.2 Selection and Monitoring of Subcontractors

Low price is not the overriding criterion for selecting a subcontractor. With involvement from Hanford Site, we will evaluate each contractor, to determine their credibility in the areas of past performance, technical capabilities, availability and proximity of resources, financial stability, safety record and price. The quality of previous work, strong safety record, history of working with Hanford Site and/or Johnson Controls, overall technical ability and compliance to the specification are highly considered. Our objective is to provide the best subcontracted value and quality for successful installation of the ECMs.

Effective subcontract management and monitoring is the result of planning, control, communication, and coordination. Contracting partners report directly to the Johnson Controls Project Manager. Specific quality plans with stringent checks and balances allow for close monitoring of all aspects surrounding our self performance and subcontractors. The Project Manager and Quality Control staff looks for patterns in missed timelines, safety violations, poor material procurements and quality problems and quickly remediates and brings issues into compliance. Regular inspections assure adequate technical performance. Frequent communication between the Project Manager, Hanford Site and the subcontractors, on-site and at Job Progress Meetings, leads to coordinated solutions to emerging concerns before they become significant. To effectively execute and manage multiple subcontractors working in multiple buildings, Johnson Controls utilizes a full time Project Manager and Safety Engineer on-site during any work.

15.2.3 Small Business, Small Disadvantaged, and Women-Owned Small Business Subcontracting

Johnson Controls is committed to small, small disadvantaged, and women-owned small business participation in all of our contracts. On average, Johnson Controls spends $1.7 billion annually with over 340 diverse companies owned by minorities, veterans and women and is 1 of 18 corporations, and the only ESCO in the world, that has earned the right to join the prestigious Billion Dollar Roundtable. Johnson Controls serves as a mentor to small disadvantaged businesses under a unique Federal GSA Mentor Protégé Agreement that provides construction services for Government, Military and Commercial facilities.

Table 6 shows the goals established under the DOE Super ESPC for planned subcontracting dollars to be subcontracted to small, small disadvantaged, and women-owned small businesses. A project-specific small, small disadvantaged, and women-owned small business subcontracting plan will be developed in the IGA.

Table 6: Small, Small Disadvantaged, and Women-Owned Small Business Subcontracting Goals

Business Type	Goals
Small Business	20%
Small-Disadvantaged Business	7%
Women-Owned Small Business	3%

15.2.4 First-Tier Subcontracting Clause Implementation

Johnson Controls will advise all subcontractors of our commitment to the small business subcontracting plan. In the event that subcontracts exceeding $500,000 are awarded, Johnson Controls will require the affected subcontractors to comply with the requirements of the small business subcontracting plan and to add the subcontracting clause into their subcontract terms and conditions. Also, for subcontracts over $500,000, the affected companies must develop a subcontracting plan.

15.2.5 Safety Plan/Safety Record

Safety is a core value of Johnson Controls. We promote the safety of our customers, facility occupants, our employees, subcontractor employees, the public, and the environment. Johnson Controls consistently outperforms the industry in safety metrics.

The overall goal of the Johnson Controls safety program is to establish an accident free culture by establishing proven procedures, the use of best practices, and involving every member of the team in the safety monitoring and alert system.

Our commitment to safety is affirmed by a company culture that is in full support of its employee's and contractor's well being and is backed up by the corporate vision statement:

A more comfortable, safe and sustainable world.

Johnson Controls believes safety is a core value critical to success.

Johnson Controls will ensure and monitor safe work practices at Hanford Site by preparing a site Accident Prevention Plan that is bolstered by our four tiers of safety and by instilling our culture of safety through training, safety meetings, task observations, site audits and inspections.

The foundations of our site-specific Hanford Site, and currently approved, Worker Safety and Health Program (WSHP) are the requirements of 10 CFR 851, 29 CFR 1910, 29CFR 1926, Hanford Site site-specific requirements and other applicable safety standards .

Our four tiers of safety include:

- A site-specific Safety and Health Officer that has completed the OSHA 30 Hour Construction Safety Course and other site requirements for education and experience.
- In addition to the Safety and Health Officer, the site Project Manager has OSHA 30 construction safety course.
- Regional safety representatives that have oversight of projects within an assigned geographical location that will provide professional assistance to site safety personnel.
- A dedicated Federal Solutions Safety, Health and Quality Manager that has direct oversight of all Government projects to ensure compliance to specific agency safety standards and to train the assigned project management staff in such standards.
- A Corporate safety team with direct oversight of regional safety managers and responsibility of ensuring compliance to all corporate safety standards and policies.

Safety is a continual process with shared responsibility at all levels of Johnson Controls and our subcontractor organizations. Every effort is made to prevent accidents and to provide safe working conditions. The foundation of the Johnson Controls safety program is training and education with daily interaction between leaders and employees guided at developing an open forum on best safety practices. Each manager, craftsman, mechanic, supervisor and subcontractor employee assigned to the Hanford Site project will be trained to current 10 CFR 851 requirements.

A project-specific addendum of the WSHP will be developed and submitted for approval within 30 days of Task Order Award. The foundation of the Worker Safety Health Program will be the requirements of 10 CFR 851, 29 CFR 1910, 29CFR 1926, Hanford Site site-specific requirements and other applicable safety standards.

15.3 Operations, Maintenance, Repairs, and Replacement

The success of an ESPC project is dependent on the newly installed equipment being properly operated and maintained. The savings calculations are dependent on the equipment operating as installed and as specified. The ultimate responsibility lies with Johnson Controls. Having performed an ESPC at Hanford Site, we understand site requirements and existing contractual arrangements for operations and management.

The preliminary service scope complements, but does not overlap, our existing Performance Period services being performed under the previous ESPC. Johnson Controls anticipates expansion of our on-site Hanford Site technical team by two FTEs to operate and maintain the new natural gas fired steam plant during the first two years of the ESPC Performance Period. Starting in the third year, the Performance Period and operating contract for the original 1997 ESPC will expire and several on-site management and technical resources will be transferred to this new ESPC to seamlessly operate and maintain the steam plant. Our existing on-site service presence will save the Government significant mobilization, training, security badging, and other expenses. The detailed operations, maintenance and R&R scope will be developed with Hanford Site during the Investment Grade Audit.

Johnson Controls' local Service Department will support the Johnson Controls on-site Hanford Site technical team. Regular office hours are from 8 a.m. to 5 p.m. weekdays. Outside of regular office hours our National Operations Center is staffed 24 hours per day, 365 days per year, with trained facility operators experienced in assisting customers with their service needs.

15.4 Training

Training is a critical part of an ESPC project because the personnel who will be operating the new equipment need to understand operating procedures of the new equipment. Johnson Controls will provide detailed O&M manuals. We will also provide hands-on training to the Hanford Site employees who will be interacting with the new equipment.

This training will occur concurrently with the startup of the new equipment or during the Acceptance Phase of the ECM. Training typically occurs once written certification has been provided, the testing of the system is complete and the Contracting Officer has approved the training course documentation. On-going training during the ESPC Performance Period is also available through Johnson Controls. Additional details of ECM training will be developed during the IGA with significant input from Hanford Site.

16. PRICE PROPOSAL

16.1 SUMMARY

Johnson Controls is pleased to provide the following Preliminary Assessment Price Proposal for ESPC Task Order 3 at Hanford Site. Task Order Price Schedules TO-1 through TO-4 (**Tables 8 through 11**) provide information on the ECMs, investment required, calculated savings, composition of ECM savings, costs per ECM and Performance Period expenses. Financial data and assumptions are listed in Table 1.

Table 7. Financial Data and Assumptions

Total Investment excluding Financial Procurement Costs and Construction Interest	$189,163,659
Financing Procurement Costs and Construction Period Interest	$18,039,746
Total Financed Amount including Financing Procurement Costs and Construction Interest	$207,203,406
Utility Company Rebates (Lenders do not allow utility rebates to be financed during the construction period. As such, the value of the rebate is deducted from the loan principal to calculate the Total Investment Financed during Construction Period. The Government is responsible for payment of the rebate dollars to Johnson Controls at the time of the first Performance Period payment.)	$0
Total Investment Financed during Construction Period	$207,203,406
Pre-Performance Period Payment consisting of Applicable Construction Period Energy, Water and O&M Savings Payable by the Government with the First Performance Period Payment	$0
Utility Company Rebates Payable by the Government with the First Performance Period Payment	$0
Total Investment less Pre-Performance Payments and Utility Company Rebates	$207,203,406
Interest Rate to be Finalized with Five Business days of Task Order Award	4.60%
Estimated Annual Energy and Water Cost Savings prior to Escalation	$1,014,915
Estimated Energy-Related Operations and Maintenance (O&M) Annual Savings prior to Escalation	$0
Estimated Total Annual Cost Savings prior to Escalation	$1,014,915
Estimated Year 1 Cost Savings	$1,192,787
Guaranteed Year 1 Cost Savings	$1,073,508
Task Order Award Date	September 30, 2016
Submission of Post-Installation Report	July 31, 2018
Project Acceptance Period Started	July 31, 2018
Government Acceptance of Post-Installation Report	August 31, 2018
Project Acceptance Received	August 31, 2018
Performance Period Start	September 1, 2018
Invoice Date for First Contractor Payment	September 30, 2018
Government Payment of First Performance Period Payment	October 31, 2018
Performance Period Loan Payment Structure	Monthly in Arrears
Performance Period Services Payment Structure	Monthly in Arrears
Construction Period Duration in Months	24
Performance Period Duration in Years	23
Task Order Contract Term in Years	25.00

16.2 TITLE

Title to all equipment installed by Johnson Controls shall be vested in the Government after acceptance by the Government and shall not relieve Johnson Controls responsibility for ECM performance. The financier of the installed ECMs may retain a security interest in the equipment and improvements, subject to and subordinate to the rights of the Government. In no event shall such security interest allow for access to Hanford Site for the purpose of disabling or removing equipment or systems without written permission from the Contracting Officer.

16.3 RISK OF LOSS

It is understood that the Contractor shall ensure the ECM equipment through the pre-Performance Period of the Task Order term (i.e. the period prior to the ECM acceptance date). Upon acceptance, title to all Contractor-installed equipment will vest with the Government. The Government will self-ensure the equipment throughout the term of the Task Order for the greater of the ECM equipment's replacement value or the Total Amount Financed as shown in Schedule TO-3. If such equipment is damaged or destroyed, thereafter, for reasons beyond the control and without the fault or negligence of the Contractor, including force majeure events, the Government will:

1. Terminate the Task Order (either in part or in whole) by paying to the Contractor the applicable amount set forth in the Termination Liability Schedule and hold the Contractor harmless for the savings and performance associated with the damaged or destroyed equipment for the remainder of the term.
2. Request a proposal from the Contractor to repair or replace the damaged equipment upon which the parties will negotiate in good faith a mutually acceptable modification to the Task Order; provided that any such repair or replacement will be at the Government's sole expense and the Government will be obligated to continue making its scheduled payments when due, or
3. Repair or replace the damaged or destroyed equipment at its cost and continue making its scheduled payments to the Contractor when due.

If pursuant to (iii), the repair/replacement work is performed by any party other than the Contractor, a commissioning of the repair/replacement work must be conducted, witnessed and presented to both the Government and the Contractor for their acceptance. This requirement is necessary for the Contractor to continue to guarantee the related energy savings. The transfer of title will not alter any other responsibility the Contractor would have had under the contract absent the transfer.

Table 8. Schedule TO-1 (Preliminary Assessment)

PROPOSED GUARANTEED SAVINGS AND CONTRACTOR PAYMENTS

IMPORTANT INFORMATION

(1) This schedule is not to be altered or changed in any way. Please note any clarifications in the comments/explanations area below.

(2) [Reserved]

(3) The guaranteed annual cost savings are based on the site-specific M&V Plan.

(4) The total of annual contractor payments represents the TO price and should be supported by information submitted.

(5) If applicable, prior to the Post-Acceptance Performance Period, Implementation Period allowable payments and energy savings are one-time amounts only.

(6) The proposed guaranteed cost savings during the Implementation Period and Post-Acceptance Performance Period must exceed the contractor payments.

(7) If applicable, submit escalation rates applied to initial estimated annual cost savings in column (a) as follows: a) energy rates: electricity = 3.71% per year, natural gas = 5.60% per year; b) energy-related O&M savings (including water and sewer) = 2.94% per year

(8) If selected, the contractor shall complete the installation of all proposed ECMs not later than 24 months after TO award.

Task Order No.:	Contractor Name:	Project Site:	
3	Johnson Controls Government Systems	Hanford National Laboratory	
	(a) Estimated Cost Savings ($)	**(b) Proposed Guaranteed Cost Savings ($)**	**(c) Contractor Payments ($)**
Implementation Period	$ -	$ -	$ -
Post-Acceptance Performance Period Year	**(d) Estimated Annual Cost Savings ($)**	**(e) Proposed Guaranteed Annual Cost Savings ($)**	**(f) Annual Contractor Payments ($)**
One	$1,192,787	$1,073,508	$1,073,507
Two	$390,309	$351,278	$351,277
Three	$670,636	$603,573	$603,572
Four	$1,374,030	$1,236,627	$1,236,626
Five	$1,636,126	$1,472,513	$1,472,512
Six	$2,383,770	$2,145,393	$2,145,392
Seven	$2,458,637	$2,212,773	$2,212,772
Eight	$2,631,971	$2,368,774	$2,368,773
Nine	$20,574,680	$18,517,212	$18,517,211
Ten	$30,858,182	$27,772,364	$27,772,363
Eleven	$31,442,845	$28,298,561	$28,298,560
Twelve	$34,677,241	$31,209,517	$31,209,516
Thirteen	$36,108,541	$32,497,687	$32,497,686
Fourteen	$35,748,038	$32,173,234	$32,173,233
Fifteen	$36,675,630	$33,008,067	$33,008,066

Sixteen	$38,611,129	$34,750,016	$34,750,015
Seventeen	$39,606,096	$35,645,486	$35,645,485
Eighteen	$42,416,560	$38,174,904	$38,174,903
Nineteen	$42,014,148	$37,812,733	$37,812,732
Twenty	$43,827,381	$39,444,643	$39,444,642
Twenty-one	$46,680,874	$42,012,787	$42,012,786
Twenty-two	$46,854,715	$42,169,243	$42,169,242
Twenty-three	$50,585,880	$45,527,292	$45,444,472
Totals	$589,420,206	$530,478,186	$530,395,343

Explanations/Comments:

Table 9. Schedule TO-2

IMPLEMENTATION PRICE BY ENERGY CONSERVATION MEASURE

IMPORTANT INFORMATION:

(1) This schedule is not to be altered or changed in any way. Please note any clarifications in the comments/explanations area below.

(2) Implementation expense shall include only direct costs for each ECM and no Post-Acceptance Performance Period expenses. Indirect expenses and profit will be applied to the sum of direct expenses for all ECMs and project development to calculate total implementation price (d) for the project.

(3) Contractor shall attach adequate supporting information detailing total implementation expenses.

(4) Contractor shall propose bonded amount representing the basis of establishing performance and payment bonds per Section H of the contract, as required.

(5) Attached supporting information shall be presented to identify portions of ECM or project expenses included in proposed bonded amount.

(6) Proposed bonded amount is assumed to include indirect expenses and profit applied to implementation expenses above, unless otherwise specified by contractor.

(7) For the following ECMs, enter the *total installed capacity of new equipment* in the units specified (e.g. chillers-150); chillers and packaged units in tons, VFDs in hp, boilers and furnaces in Btu/hr, BAS/EMCS in number of points, transformers in kVA, generators in kW. For lighting ECMs, specify the Baseline kW treated.

(8) M&V expense shall not include any Performance Period expenses.

Project Site:			**Task Order No:**		**Contractor Name:**			
Hanford National Laboratory			3		Johnson Controls Government Systems			
					Implementation Expense			
Tech Category (TC)	**ECM No.**	**Equipment Description - Title**	**ECM Size**	**M&V Expense ($)**	**(a) Direct ($)**	**(b) Indirect ($)**	**(c) Profit ($)**	**(d) Implement'n Price: Totals (a)+(b)+(c)= (d)**
TC.19	19.1	ESPC Proposal Development	6,000,000 SF		$2,517,598	$460,076	$169,324	**$3,146,997**
TC.1	1.1	Natural Gas Fired Steam Plant and Natural Gas Pipeline	10,000 Boiler HP	$130,436	$83,515,710	$15,261,995	$5,616,933	**$104,394,637**
		Cascade Natural Gas Pipeline Expense	N/A					**Excluded**
		Funding Available for Other ECM Development	N/A					**$68,509,537**
		ESPC Project Direct Costs (Less Project Development)			$10,489,991	$1,916,983	$705,515	**$13,112,488**
Totals								**$189,163,659**
Bonded Amount ($)								**$189,163,659**

Explanations/Comments:

Table 10. Schedule TO-3 (4 pages)

POST-ACCEPTANCE PERFORMANCE PERIOD CASH FLOW

Project Site:		**Task Order No:**		**Contractor Name:**			
Hanford National Laboratory		3		Johnson Controls Government Systems			
Project Capitalization		Applicable Financial Index:		TBD	Issue Date:		TBD
Total Implementation Price (from TO-2 Total)	$189,163,659	Term (Years):		TBD	Source:		TBD
Plus Financing Procurement Price ($)	$18,039,746	Index Rate:		3.00%	Effective Through:		
Less Implementation Period Payments (from TO-1 (Final) (c)) (If proposed, must be fully documented)	$0	Added Premium (adjusted for tax incentives):		1.60%	Rate to be finalized within 5 days of award		
Total Amount Financed (Principal)	$207,203,406	Project Interest Rate:		4.60%	Payment Type:	Monthly in Arrears	
Term	**23**	**1**	**2**	**3**	**4**	**5**	**6**
Annual Cash Flow (Post-Acceptance Performance Period)							
Debt Service							
Principal Repayment ($)		-$9,946,128	-$11,187,488	-$13,277,444	-$13,349,112	-$13,835,538	-$13,897,197
Less Incentives (i.e. REC, White Tags, etc.)		$0	$0	$0	$0	$0	$0
Net Principal Repayment Before Interest ($)		-$9,946,128	-$11,187,488	-$13,277,444	-$13,349,112	-$13,835,538	-$13,897,197
Interest ($)		$9,739,316	$10,222,793	$10,781,115	$11,393,376	$12,017,606	$12,655,330
	Total Debt Service (a)	-$206,812	-$964,695	-$2,496,328	-$1,955,736	-$1,817,932	-$1,241,868
Post-Acceptance Performance Period Expenses							
Management/Administration		$69,362	$71,403	$73,504	$75,666	$77,893	$80,184
Operation		$0	$0	$0	$0	$0	$0
Maintenance		$0	$0	$0	$0	$0	$0
Repair and Replacement		$0	$0	$0	$0	$0	$0
Measurement and Verification		$166,468	$171,366	$176,408	$181,599	$186,942	$192,442
Permits and Licenses		$0	$0	$0	$0	$0	$0
Insurance		$0	$0	$0	$0	$0	$0
Property Taxes		$0	$0	$0	$0	$0	$0
Natural Gas Fired Steam Plant Operation, Maintenance and Repair and Replacement		$788,425	$810,009	$2,230,008	$2,296,624	$2,367,521	$2,437,181
Other 2:		$0	$0	$0	$0	$0	$0
Other 3:		$0	$0	$0	$0	$0	$0
	Subtotal Before Application of Indirect Rates	$1,024,255	$1,052,778	$2,479,920	$2,553,889	$2,632,356	$2,709,808
Indirect Cost Rate (%)		$0	$0	$0	$0	$0	$0
Indirect Cost Applied ($)		$187,177	$192,389	$453,191	$466,708	$481,047	$495,201
	Subtotal Post-Acceptance Performance Period Expenses	$1,211,432	$1,245,167	$2,933,111	$3,020,597	$3,113,403	$3,205,009
Post-Acceptance Performance Period Profit (%)		$0	$0	$0	$0	$0	$0
Post-Acceptance Performance Period Profit ($)		$68,887	$70,806	$166,790	$171,764	$177,042	$182,251
	Total Post-Acceptance Performance Period Expenses (b)	$1,280,319	$1,315,972	$3,099,900	$3,192,362	$3,290,445	$3,387,259
Total - Amount Contractor Payments (a) + (b)		$1,073,507	$351,277	$603,572	$1,236,626	$1,472,512	$2,145,392
Explanations/Comments:							

Table 10. Schedule TO-3 (Page 2)

POST-ACCEPTANCE PERFORMANCE PERIOD CASH FLOW

Project Site:	**Task Order No:**		**Contractor Name:**			
Hanford National Laboratory	3		Johnson Controls Government Systems			
Term	**7**	**8**	**9**	**10**	**11**	**12**
Annual Cash Flow (Post-Acceptance Performance Period)						
Debt Service						
Principal Repayment ($)	-$14,583,092	-$15,213,694	$444,134	$9,805,301	$10,689,787	$14,042,602
Less Incentives (i.e. REC, White Tags, etc.)	$0	$0	$0	$0	$0	$0
Net Principal Repayment Before Interest ($)	-$14,583,092	-$15,213,694	$444,134	$9,805,301	$10,689,787	$14,042,602
Interest ($)	$13,308,942	$13,992,949	$14,365,396	$14,149,238	$13,679,700	$13,117,868
Total Debt Service (a)	-$1,274,150	-$1,220,745	$14,809,530	$23,954,538	$24,369,488	$27,160,470
Post-Acceptance Performance Period Expenses						
Management/Administration	$82,544	$84,972	$87,472	$90,046	$92,696	$95,423
Operation	$0	$0	$0	$0	$0	$0
Maintenance	$0	$0	$0	$0	$0	$0
Repair and Replacement	$0	$0	$0	$0	$0	$0
Measurement and Verification	$198,105	$203,933	$209,934	$216,111	$222,469	$229,015
Permits and Licenses	$0	$0	$0	$0	$0	$0
Insurance	$0	$0	$0	$0	$0	$0
Property Taxes	$0	$0	$0	$0	$0	$0
Natural Gas Fired Steam Plant Operation, Maintenance and Repair and Replacement	$2,508,890	$2,582,709	$2,668,738	$2,748,103	$2,828,093	$2,914,799
Other 2:	$0	$0	$0	$0	$0	$0
Other 3:	$0	$0	$0	$0	$0	$0
Subtotal Before Application of Indirect Rates	$2,789,538	$2,871,614	$2,966,145	$3,054,259	$3,143,258	$3,239,237
Indirect Cost Rate (%)	$0	$0	$0	$0	$0	$0
Indirect Cost Applied ($)	$509,771	$524,770	$542,045	$558,148	$574,411	$591,951
Subtotal Post-Acceptance Performance Period Expenses	$3,299,309	$3,396,385	$3,508,190	$3,612,407	$3,717,669	$3,831,188
Post-Acceptance Performance Period Profit (%)	$0	$0	$0	$0	$0	$0
Post-Acceptance Performance Period Profit ($)	$187,613	$193,133	$199,491	$205,417	$211,403	$217,858
Total Post-Acceptance Performance Period Expenses (b)	$3,486,923	$3,589,518	$3,707,681	$3,817,824	$3,929,072	$4,049,046
Total - Amount Contractor Payments (a) + (b)	$2,212,772	$2,368,773	$18,517,211	$27,772,363	$28,298,560	$31,209,516

Table 10. Schedule TO-3 (Page 3)

POST-ACCEPTANCE PERFORMANCE PERIOD CASH FLOW

Project Site:	**Task Order No:**		**Contractor Name:**			
Hanford National Laboratory	3		Johnson Controls Government Systems			
Term	**13**	**14**	**15**	**16**	**17**	**18**
Annual Cash Flow (Post-Acceptance Performance Period)						
Debt Service						
Principal Repayment ($)	$15,895,575	$16,189,545	$17,674,491	$20,150,330	$21,875,616	$25,344,102
Less Incentives (i.e. REC, White Tags, etc.)	$0	$0	$0	$0	$0	$0
Net Principal Repayment Before Interest ($)	$15,895,575	$16,189,545	$17,674,491	$20,150,330	$21,875,616	$25,344,102
Interest ($)	$12,433,165	$11,695,822	$10,920,055	$10,055,262	$9,092,274	$8,013,474
Total Debt Service (a)	$28,328,740	$27,885,367	$28,594,546	$30,205,592	$30,967,889	$33,357,577
Post-Acceptance Performance Period Expenses						
Management/Administration	$98,231	$101,121	$104,096	$107,159	$110,312	$113,557
Operation	$0	$0	$0	$0	$0	$0
Maintenance	$0	$0	$0	$0	$0	$0
Repair and Replacement	$0	$0	$0	$0	$0	$0
Measurement and Verification	$235,753	$242,690	$249,830	$257,181	$264,748	$272,538
Permits and Licenses	$0	$0	$0	$0	$0	$0
Insurance	$0	$0	$0	$0	$0	$0
Property Taxes	$0	$0	$0	$0	$0	$0
Natural Gas Fired Steam Plant Operation, Maintenance and Repair and Replacement	$3,001,174	$3,086,482	$3,176,890	$3,271,198	$3,367,017	$3,467,766
Other 2:	$0	$0	$0	$0	$0	$0
Other 3:	$0	$0	$0	$0	$0	$0
Subtotal Before Application of Indirect Rates	$3,335,157	$3,430,293	$3,530,816	$3,635,538	$3,742,077	$3,853,861
Indirect Cost Rate (%)	$0	$0	$0	$0	$0	$0
Indirect Cost Applied ($)	$609,480	$626,865	$645,235	$664,373	$683,842	$704,270
Subtotal Post-Acceptance Performance Period Expenses	$3,944,637	$4,057,158	$4,176,052	$4,299,911	$4,425,919	$4,558,131
Post-Acceptance Performance Period Profit (%)	$0	$0	$0	$0	$0	$0
Post-Acceptance Performance Period Profit ($)	$224,309	$230,708	$237,469	$244,512	$251,677	$259,195
Total Post-Acceptance Performance Period Expenses (b)	$4,168,947	$4,287,866	$4,413,520	$4,544,423	$4,677,596	$4,817,326
Total - Amount Contractor Payments (a) + (b)	$32,497,686	$32,173,233	$33,008,066	$34,750,015	$35,645,485	$38,174,903

Table 10. Schedule TO-3 (Page 4)

POST-ACCEPTANCE PERFORMANCE PERIOD CASH FLOW

Project Site:	**Task Order No:**		**Contractor Name:**			
Hanford National Laboratory	3		Johnson Controls Government Systems			
Term	**19**	**20**	**21**	**22**	**23**	**Totals**
Annual Cash Flow (Post-Acceptance Performance Period)						
Debt Service						
Principal Repayment ($)	$26,022,948	$28,762,783	$32,580,687	$34,116,426	$38,898,773	$207,203,406
Less Incentives (i.e. REC, White Tags, etc.)	$0	$0	$0	$0	$0	$0
Net Principal Repayment Before Interest ($)	$26,022,948	$28,762,783	$32,580,687	$34,116,426	$38,898,773	$207,203,406
Interest ($)	$6,833,452	$5,579,110	$4,176,195	$2,645,374	$974,294	$231,842,106
Total Debt Service (a)	$32,856,399	$34,341,893	$36,756,882	$36,761,800	$39,873,067	$439,045,512
Post-Acceptance Performance Period Expenses						
Management/Administration	$116,899	$120,338	$123,879	$127,524	$131,276	$2,235,555
Operation	$0	$0	$0	$0	$0	$0
Maintenance	$0	$0	$0	$0	$0	$0
Repair and Replacement	$0	$0	$0	$0	$0	$0
Measurement and Verification	$280,557	$288,812	$297,309	$306,057	$315,062	$5,365,331
Permits and Licenses	$0	$0	$0	$0	$0	$0
Insurance	$0	$0	$0	$0	$0	$0
Property Taxes	$0	$0	$0	$0	$0	$0
Natural Gas Fired Steam Plant Operation, Maintenance and Repair and Replacement	$3,567,611	$3,673,049	$3,783,535	$3,892,373	$4,010,786	$65,478,980
Other 2:	$0	$0	$0	$0	$0	$0
Other 3:	$0	$0	$0	$0	$0	$0
Subtotal Before Application of Indirect Rates	$3,965,066	$4,082,199	$4,204,723	$4,325,954	$4,457,124	$73,079,865
Indirect Cost Rate (%)	$0	$0	$0	$0	$0	
Indirect Cost Applied ($)	$724,592	$745,997	$768,388	$790,542	$814,513	$13,354,907
Subtotal Post-Acceptance Performance Period Expenses	$4,689,658	$4,828,197	$4,973,111	$5,116,496	$5,271,636	$86,434,772
Post-Acceptance Performance Period Profit (%)	$0	$0	$0	$0	$0	
Post-Acceptance Performance Period Profit ($)	$266,675	$274,552	$282,793	$290,946	$299,768	$4,915,059
Total Post-Acceptance Performance Period Expenses (b)	$4,956,333	$5,102,749	$5,255,904	$5,407,442	$5,571,405	$91,349,832
Total - Amount Contractor Payments (a) + (b)	$37,812,732	$39,444,642	$42,012,786	$42,169,242	$45,444,472	$530,395,343

Table 11. *Schedule TO-4*

TASK ORDER PERFORMANCE PERIOD FIRST YEAR ESTIMATED ANNUAL COST SAVINGS, by ENERGY CONSERVATION MEASURE and TECHNOLOGY CATEGORY

IMPORTANT INFORMATION:

(1) Project square footage (in 1000 SF) - Include only building square footage affected by installed ECMs in project.

(2) For column (a) insert estimated energy Baseline by ECM and total project in MBtu based on IGA, and proposal data.

(3) For column (c1), annual electric demand savings (kW/yr) is the sum of the monthly demand savings.

(4) Energy conversion factors for MBtu: MBtu=10^6 Btu; Electricity - 0.003413 MBtu/kWh; Natural Gas - 0.1 MBtu/therm ; #2 Oil -0.128 MBtu/gal.

(5) Specify "Other" energy savings in (e)(1) and (e)(2) as applicable. Include energy type Diesel Fuel; energy units MBtu; and Btu conversion factor 130,500 Btu/ Gallon (unit).

(6) This schedule is not to be altered or adapted in any way. Please note any clarifications in the comments/explanations area below.

Project Site:	Task Order No:	Contractor Name:	Project Square Footage (KSF)
Hanford National Laboratory	1	Johnson Controls Government Systems	6,000

Tech No. Att 2	ECM No.	(a) ECM Energy Baseline (MBtu/yr)	(b1) Electric Energy Savings (kWh/yr)	(b2) Electric Energy Savings ($/yr)	(c1) Electric Demand Savings (kW/yr)	(c2) Electric Demand Savings ($/yr)	(d1) Natural Gas Savings (MBtu/yr)	(d2) Natural Gas Savings ($/yr)	(e1) Other Savings (MBtu/yr)	(e2) Other Savings ($/yr)	(f)= 0.003413* b1+d1+e1 Total Energy Savings (MBtu/yr)	(g)= b2+c2+d2+e2 Total Energy Cost Savings ($/yr)	(h) Other Energy-Related and O&M Cost Savings ($/yr)	(i) Water Savings (1000 gal/yr)	(j) Water Savings ($/yr)	(k)= (g)+(h)+(j) Estimated Annual Cost Savings ($/yr)	(l) Implementation Price ($)	(m)= (l)/(k) Simple Payback (yrs)
TC.19	19.1																$3,146,997	
TC.1	1.1		(2,683,200)	-$103,037			(104,057)	-$765,310	60,690	$2,061,134	(52,525)	$1,192,787				$1,192,787	$104,394,637	87.52
Other	Other																$68,509,537	
ECM Implementation Price			(2,683,200)	-$103,037			(104,057)	-$765,310	60,690	$2,061,134	(52,525)	$1,192,787				$1,192,787	$176,051,171	147.60
ESPC Project Direct Costs (Less Project Development)																	$13,112,488	
Total			(2,683,200)	-$103,037	-	$0	(104,057)	-$765,310	60,690	$2,061,134	(52,525)	$1,192,787	$0	-	$0	$1,192,787	$189,163,659	158.59

Explanations/Comments:

1. Energy savings and cost savings appearing in this schedule represent year 1 of the Performance Period. Savings increase significantly later in the Performance Period as the throughput of the waste treatment plant increases. The increase in annual savings is portrayed on Schedule TO-1.
2. Utility rates were escalated to refelct year 1 of the Performance Period.

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Appendix G

Other Potential Cost Savings

Contents

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OTHER POTENTIAL COST SAVINGS (1.4)

This section will list and valuate other cost savings gained by constructing and operating an SMR in the Tri Cities region. Examples include use of the Hazardous Materials Management and Emergency Response (HAMMER) facility for training, local nuclear fuel fabrication and transportation services, and local NQA-1 certified vendors. This section also will list community features that are synergistic with construction and operation of a first-of-a-kind reactor at Hanford, such as local and regional universities, PNNL, trained nuclear construction and operations workforces and local Environmental Protection Agency (EPA) and Washington State Department of Ecology Offices. This section will result in a credible cost advantage value that will be used in the overall evaluation of the Hanford SMR economics.

Existing Tri-Cities Area Nuclear Workforce, Economy, and Business Climate Excellent

The Hanford Site, major employer and economic driver in the Tri-Cities, has performed pioneering nuclear work since its founding in World War II. It produced the plutonium in the world's first and third atomic bombs, and produced two/thirds of the defense plutonium ever manufactured by the United States. For the past 25 years, it has performed the largest environmental cleanup project in world history.[1]

The Tri-Cities, home communities of the Hanford Site, constitute the fourth largest Metropolitan Statistical Area in Washington State. Approximately half of its population of 250,000 is employed, with about 20,000 employed in nuclear work as direct government or government contractor employees. In addition, the Tri-Cities has strong trade, transport and utilities sectors (17,500 jobs) much of which supports nuclear government work, and a vibrant and growing manufacturing sector (8,000 jobs) that includes several technical engineering companies that specialize in nuclear work. The Tri-Cities unemployment rate stands at 5.7 percent in mid-2014, below the Washington State average. The Tri-Cities workforce is highly educated, with more scientists and engineers per capita than anywhere else in the nation. Slightly more than 82 percent of the Tri-Cities population has a high school, college or graduate education.[2]

Approximately $3 billion in federal money comes into the Tri-Cities every year, providing a solid economic base. Much of this money is mandated in law, and is allocated to fund nuclear remediation work that is expected to last until at least 2070. The ongoing cost of nuclear remediation work is estimated by the government to be more than $113 billion over the next 56 years.[3] In 2010 CNN/Money rated the Tri-Cities as one of the top 10 likeliest places to see increases in housing values, due to its stable economy, and in 2011 the U.S. Census Bureau said that the Tri-Cities was the fastest-growing metropolitan area in the nation. In 2010, the Tri-Cities was also rated by Kiplinger as one of the top 10 places in the nation to raise a family. The average household income for the Tri-Cities region has increased 21.5 percent since 2000, and now stands at approximately $68,000 – more than 30 percent above the national average. Yet, the Tri-Cities has the lowest Cost of Living index in Washington State, and stands at

[1] Gerber, Michele S., "On the Home Front: The Cold War Legacy of the Hanford Nuclear Site," University of Nebraska Press (Lincoln), 1992, 1997, 2002 and 2007.
[2] Tri Cities Development Council (TRIDEC), "Tri-Cities Economy," TRIDEC (Kennewick, WA), 2010 at http://www.tridec.org/site_selection/tri-cities_economy/
[3] U.S. DOE "2014 Hanford Lifecycle Cost, Schedule and Scope Report,' DOE/RL-2013-02, Rev 1, U.S. DOE (Richland, WA), January 2014.

20 percent below national average costs.[4] A favorable business climate is enhanced by the fact that Washington State is one of only seven states that does not levy corporate, unitary or personal income taxes. Washington State also does not tax inventory, interest, dividends or capital gains.[5]

Existing and Future Nuclear Support Companies

Major Hanford Contractors

Five large, international engineering and construction companies anchor the major nuclear construction, treatment and remediation contracts at the Hanford Site. Together, Bechtel, CH2MHill, and URS, with major subcontractors Areva and Energy Solutions perform work amounting to nearly $2-Billion per year. These companies and their employees have expertise in nuclear construction, facility management and operations, nuclear safety, and environmental remediation of hazardous and radioactive wastes. Each company also has corporate "reach-back" that allows it to deploy additional nuclear expertise as needed.

Hanford Subcontractors and Other Tri-Cities Engineering Companies

The Tri-Cities is home to dozens of engineering, design, fabrication, testing and manufacturing businesses that serve as subcontractors to the major Hanford contractors. Some of these companies are small and independent, and some are divisions of large engineering corporations such as Fluor. These companies specialize in nuclear work, and some possess Nuclear Quality Assurance Level 1 (NQA-1) certifications in welding and other aspects of nuclear work. In fact, the Tri-Cities is among a very small number of areas of the United States that has a cluster of NQA-1 certified companies. Together, the nuclear-based small businesses in the Tri-Cities employ more than 150 professionals with skills to support all aspects of commercial nuclear facility management and oversight, design, licensing, operations, and maintenance.[6]

Pacific Northwest National Laboratory

PNNL is one of ten national laboratories managed by the DOE Office of Science. Recognized as a technology-driven research laboratory, PNNL also has vast experience in applied materials science and process engineering, applied nuclear science and technology, licensing, environmental capabilities, and ongoing relationship with clients such as the National Nuclear Security Administration, DOE Office of Nuclear Energy, and the NRC. PNNL is the "go-to" laboratory for the NRC for environmental issues, fuel qualification reviews and risk assessments. PNNL developed the Design-Specific Review Standards for SMRs in conjunction with the NRC, and led the national study on used fuel storage. It has facilities, including the Radiochemical Processing Laboratory, equipped with hot cells, glove boxes, instrumentation and other equipment needed to create and implement state-of-the-art nuclear processes. PNNL has nearly 5,000 employees, does approximately$1 billion worth of business each year, and is the largest employer in the Tri-Cities.[7]

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[4] Cockle, Richard, "Tri-Cities Combine for Nation's Fastest Growing Metro Area, Boosted by Federal Money to Mop up Hanford," in *Oregoni*an (Portland), December 5, 2012; Dupler, Michelle, "Tri-Cities Growth Recognized," in *Tri-City Herald* (Kennewick, WA), November 28, 2012, pp. A1-A2; Dupler, Michelle, "They Grow So Fast," in *Tri-City Herald*, April 6, 2012, pp. A1-A2.
[5] TRIDEC, "Tri-Cities Economy," 2010.
[6] Tri-City Regional Chamber of Commerce, 'Business Directory," Tri-City Regional Chamber of Commerce (Kennewick, WA), 2013 at http://www.tricityregionalchamber.com/search
[7] Pacific Northwest National Laboratory (PNNL), "About PNNL," PNNL, 2013 at http://www.pnnl.gov/about/

Energy Northwest

ENW, a not-for-profit joint operating agency, develops, owns and operates the Northwest's only nuclear energy utility, the Columbia Generating Station, on leased land on the Hanford Site. ENW also owns and operates a diverse mix of electricity generating resources, including hydro, solar and wind projects ENW has teamed with NuScale Power and Utah Associated Municipal Power Systems as part of the Western Initiative for Nuclear Project to promote a commercial, SMR project in the western US, ENW holds first right of offer to operate the project.[8]

Hanford Atomic Metal Trades Council

The Hanford Atomic Metal Trades Council (HAMTC) is a labor organization headquartered in the Tri-Cities and composed of 15 different craft unions working at Hanford. HAMTC has represented workers at Hanford since 1948 and is the exclusive bargaining agent for approximately 3,000 employees today. These workers represent one of the largest collections of experienced nuclear workers in the nation and, combined, have many thousands of years of nuclear experience.[9]

Nuclear Support Programs at Local Educational Institutions

Recognizing the need for robust and targeted nuclear programs to address current and future workforce needs, companies from the Tri-Cities have teamed with Columbia Basin College (CBC) and Washington State University (WSU) Tri-Cities to ensure that the labor force of tomorrow is trained and developed to sustain nuclear work. In addition, extensive local utility and workforce training facilities and programs ensure continuing development of employee nuclear skills.

An example of focused training is the Nuclear Technology program developed in 2009 with the help of about 13 local contractors, including Energy Northwest and URS. The program is administered through CBC, which is only the third college in the nation to be certified to offer the National Academy for Nuclear Training Certificate. In this program, students earn an AAS degree in nuclear technology in one of three option areas: radiation protection technician, instrumentation and control technician, and non-licensed operator (an option added in 2011). Initially, grants from the NRC and DE provided for curriculum development, equipment purchases, scholarships, and salary for an administrator of the program. Today, the program is funded by student fees and support from Hanford Site contractors Washington River Protection Solutions and CH2MHill Plateau Remediation.[10]

WSU has offered college courses in the sciences, engineering, health physics, and other nuclear-related fields from its participation in the Joint Center for Graduate Study in the Tri-Cities in July 1958. In 1989, WSU formally established a branch campus in the Tri-Cities, and now offers engineering and technology courses designed to provide a continual flow of qualified personnel to support the nuclear industry. A nuclear engineering emphasis within the WSU College of Engineering and Architecture has recently been developed to address the growing need for local

[8] Energy Northwest (ENW), "Who We Area," ENW (Richland, WA), 2014 at http://www.energy-northwest.com/whoweare/Pages/default.aspx

[9] Hanford Atomic Metal Trades Council (HAMTC), "About," HAMTC (Richland, WA), 2013 at https://www.facebook.com/pages/Hanford-Atomic-Metal-Trades-Council-HAMTC/181384505208964?sk=info

[10] Columbia Basin College (CBC), "Largest Number of Nuclear Technology Graduates to Receive National Certificate," CBC (Pasco, WA), August 6, 2014 at http://www.columbiabasin.edu/index.aspx?page=1390&recordid=1130

and national nuclear engineering expertise. WSU Tri-Cities collaborates with local companies such as PNNL and Hanford Site contractors to provide internship opportunities to college students, creating a basis for future employment and a continual pipeline of young talent to support work on a SMR.[11]

Other Community Resources

HAMMER Training Facility

A nearly unprecedented and unlimited array of hazardous materials training, including Fire Fighter training, can be leveraged through the Volpentest Hazardous Materials Management and Emergency Response (HAMMER), located on the Hanford Site. HAMMER occupies a 120-acre campus and composed of numerous training and education props, aids and facilities to simulate real-life hazardous environments. The props can be reconfigured to meet a variety of unique training requirements. It is one of the few centers in the world, and the only center west of the Mississippi River that has combined this extensive array of different training material in one setting. The center's credo, "Training as Real as it Gets," indicates the realistic, hands-on training experiences available. HAMMER has concentrated its activities into five major areas: (1) Hanford worker training; (2) emergency planning, management, operations, and response; (3) security; (4) recovery; and (5) technology. HAMMER uses blended-learning, hands-on activities, lessons-learned, and cutting edge technology, and can either develop and secure training programs for customers or rent classroom space and/or props. It adjoins the 10,000-acre Hanford Patrol Training Center and uses the patrol training road track and other resources.[12]

Energy Northwest Resources:

Training: Qualified and certified trainers at ENW provide in-house facility-specific maintenance, operations, radiation safety, and security force training to staff members. Significant cost avoidance can be realized by utilizing this existing training.

Industrial Development Complex: The Industrial Development Complex (IDC) is located east of Columbia Generating Station on and leased from the Hanford Site, and is comprised of warehouse, office space and associated property in excess of Energy Northwest's current operating needs. The site is currently 57 percent occupied, and is expected to become more available after its current primary tenant, Washington Closure Hanford, completes its Hanford cleanup contract in 2015. The IDF is capable of supplying both back up water and power to Columbia Generating Station, as needed, and IDC staff members offer a variety of training and support functions during the reactor's biennial refueling outages. The following facilities, services and programs are available (with minor modifications):

- Office space (modify instead of buying/constructing temporary office space)
- Warehouse space
- Back-up Water and Power
- Fire Protection
- Chemical Control Programs and Facilities
- Fabrication Facilities

[11] Washington State University, Tri-Cities (WSU-TC), "Study Nuclear Engineering at WSU Tri-Cities," WSU-TC (Richland, WA), 2013 at http://tricities.wsu.edu/nuclearengineering/

[12] Hazardous Materials Management and Emergency Response (HAMMER) Training Center, "What is HAMMER?" Volpentest HAMMER Training Center, 2013 at https://www.hammertraining.com/page.cfm/WhatisHAMMER

- Storage/lay-down area – graded and flat
- Roads constructed for heavy-duty use/transportation
- Fenced location – about 6,000 sq ft
- Security lighting
- NQA-1 procedures in place / QA inspections and audits
- Robust QA program for welding, etc.

A new Emergency Preparedness Center is being built near the IDC. Fire and Ambulance service is currently provided by the Hanford Site, but Energy Northwest is exploring the possibility of building an additional Fire Station in close proximity to the IDC. These facilities would augment cost avoidance, as Energy Northwest will have built them by the time the SMR would come on line.[13]

Other Tri-Cities Assets and Resources:

Transportation infrastructure in the form of road, barge, and rail are in place and available for use in and around the Tri-Cities. The Tri-Cities is served by Interstate Highway 82, directly connecting to the three nearby transcontinental Interstate Highways, I-84, I-90, and I-5. A maintained road system leading to the proposed site for the SMR is safe, compliant and reliable for personnel and movement of materials and products. This road system includes specifically designed and constructed roads to the IDC to accommodate very heavy loads of materials.

The Tri-Cities offers mainline rail freight services by both Burlington Northern Santa Fe and Union Pacific Railroads. Short-line rail service to the IDC is provided by Tri-City and Olympia Railroad Company.

Barges currently traverse the Snake River and the Columbia River, transporting sealed reactor sections from U.S. Navy nuclear submarines for burial on the Hanford Site. The barge system could easily be used to transport parts for the SMR. Barge slip access is within 10 miles of the Energy Northwest site.[14]

Located in the Tri-Cities, Lampson International, LLC supports construction of nuclear facilities anywhere in the world. Lampson has previously supported the construction of many facilities on the Hanford Site including the Columbia Generating Station and the unfinished WNP-1 and 4 power plants. Lampson offers equipment rental, full service heavy lift and transportation, heavy rigging operations, specialized equipment design/build, lift and transport engineering and Project Management with vast experience in all of these realms in both general and nuclear construction environments. Lampson is also familiar with water transportation offload, rail offload, and over the road transport of extremely heavy and outsize cargo at the Hanford Site, as demonstrated by the offload and transport of decommissioned submarine reactors from barges for burial on the Hanford Site. Lampson headquarters facility, fabrication shops and maintenance facility are all located less than 30 miles from the Energy Northwest complex, allowing quick response and access to their full cadre of resources at any time.[15]

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[13] ENW, "Facilities Leasing," ENW, 2014 at http://www.energy-northwest.com/doingbusinesswithus/technicalservices/facilitiesleasing/Pages/default.aspx
[14] TRIDEC, "Tri-Cities Economy," 2010.
[15] Lampson International, "Lampson Services," Lampson International (Kennewick, WA), 2011 at http://www.lampsoncrane.com/Services.html

Summary

It is estimated that about 380 staff members (security, operations, health physics technicians, maintenance, and administrative support) are needed to effectively operate an SMR. Economies of scale can be realized, as these skill sets are currently in place at Energy Northwest and can be augmented to accommodate a new SMR. In addition, appropriate resources are available through several contractors at the Hanford Site whose work scope will diminish through the next several years. Local employers currently work to transition employees from one company to another to accommodate work scope, and this business practice is expected to continue to support the SMR.

Political support of DOE's initiative to facilitate the development of SMRs in the United States and promote a domestic SMR industry that will advance carbon-free energy and avoid the financial burden imposed by large nuclear reactor plant construction is strong and is documented with letters from Governor Jay Inslee, Former Washington State Governor Christine O. Gregoire, US Senators, members of the House of Representatives, and the Washington State Legislature. Washington State Senator Sharon Brown, representing the 8th District which includes the Tri-Cities, co-sponsored a bill to create a state Joint Select Task Force on Nuclear Energy and has been named to support it. The purpose of the Task Force is to consider whether increased nuclear power production is a viable and cost-effective way to reduce the state's use of carbon-emitting fossil fuels.[16]

All the key elements – technical expertise; workforce; and, education and training, infrastructure and political support – combine to make placement of an SMR on the Hanford Site a cost-effective decision.

References

Weiher, P. (2014). *RE: Hanford SMR Planning Strategy*. [email].

[16] Washington State House of Representatives, "Technology & Economic Development Committee, SSB 5991," Washington State House of Representatives (Olympia), 2014 at http://apps.leg.wa.gov/documents/billdocs/2013-14/Pdf/Bill%20Reports/House/5991-S%20HBA%20TED%2014.pdf